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TKE UN

**2004
ANNUAL
REPORT**

TKE ENERGY
TRUST

CORPORATE PROFILE

TKE Energy Trust ("TKE" or the "Trust") commenced business on November 2, 2004 upon the re-organization of TUSK Energy Inc. by way of Plan of Arrangement. The re-organization has been accounted for using the continuity of interest method. Accordingly, all financial and operating information has been reported as if TKE Energy Trust had always carried on the business of TUSK Energy Inc.

TKE is a new trust committed to delivering consistent distributions to the holders of its Units. The current distribution level is set at \$0.12 per Unit per month. The fourth monthly distribution of \$0.12 per Unit was paid to Unitholders on April 15th, 2005.

The Trust will take a conservative approach to business by striving to maintain commodity balance in both production and reserves, pursuing a balanced program of exploration, development and acquisition and managing commodity price risk through a comprehensive price risk management program.

TKE Energy Trust trades on the Toronto Stock Exchange ("TSX") under the symbol "TKE.UN".

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WEBSITE

TKE Energy Trust maintains an internet site at www.tketrust.com which includes new releases, tax information, distribution history, analyst reports and other information of interest to holders of Units.

UNITHOLDER INFORMATION

As of December 31, 2004 the number of trust units and exchangeable shares outstanding was 17,664,573. The Annual & Special Meeting of the Unitholders of TKE Energy Trust will be held at 3:00 p.m. Calgary time on Wednesday, June 1, 2005 at The Calgary Petroleum Club, 319 – 5th Avenue S.W., Calgary, Alberta.

FINANCIAL HIGHLIGHTS

(Canadian dollars except unit and per unit amounts)

For the years ended December 31,	2004	2003 ⁽¹⁾	Change ⁽²⁾
Income Statement			
Revenue (Net of Royalties)	58,012,753	49,534,583	17%
Cash Flow from Operations	39,471,563	36,240,787	9%
Per Unit	2.39	2.74	(13%)
Per boe	20.59	21.47	(4%)
Cash Distributions per Unit	0.12	—	—
Net Income	5,503,523	10,158,976	(46%)
Per Unit			
Capitalization ⁽³⁾			
Weighted Average Units	16,484,051	13,201,184 ⁽⁴⁾	25%
December 31, 2004 Units	17,664,573	16,213,853 ⁽⁴⁾	9%
Market Capitalization	168,873,318	122,576,729	38%
Enterprise Value	202,643,318	167,876,729	21%
Balance Sheet			
Working Capital Deficit ⁽⁵⁾	(10,308,049)	(4,184,745)	146%
Total Assets	167,034,918	171,123,969	(2%)
Bank Indebtedness	33,670,000	45,300,000	(26%)

(1) The conversion of TUSK Energy Inc. to a Trust has been accounted for as a continuity of interest. Accordingly, the consolidated financial statements of TKE Energy Trust for 2004 reflect the financial position, results of operations and cash flows as if the Trust had always carried on the business formerly carried on by TUSK Energy Inc. The year ended December 31, 2004 reflects the results of operations and cash flows of TUSK Energy Inc. and its subsidiaries for the period January 1 to November 1, 2004 and the results of operations and cash flows of the Trust and its subsidiaries for the period November 2 to December 31, 2004. The comparative figures are the results of TUSK Energy Inc. and its subsidiaries. Due to the conversion into an energy trust, certain information included in the financial statements for prior periods may not be directly comparable.

The term "units" has been used to identify both the Trust units and exchangeable shares of the Trust issued on or after November 2, 2004 as well as the common shares of the TUSK Energy Inc. outstanding prior to the conversion on November 2, 2004.

(2) Certain items were negatively impacted, when compared to the prior year, in part due to the Trust having received less than all of the assets of TUSK Energy Inc. after the re-organization.

(3) Includes units and exchangeable shares.

(4) Represents 26,402,368 weighted average common shares and 32,427,705 common shares of TUSK Energy Inc. after conversion for comparative purposes.

(5) Before bank indebtedness.

Boe Presentation – Barrels of oil equivalent may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf: 1 bbl of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. All boe conversions in this report are derived by converting gas to oil in the ratio of six thousand cubic feet of gas to one barrel of oil.

OPERATING HIGHLIGHTS

For the years ended December 31,	2004	2003 ⁽¹⁾	Change ⁽²⁾
Daily Production			
Oil (bbls)	1,124	1,390	(19%)
Natural Gas (Mcf)	22,134	17,710	25%
Natural Gas Liquids (bbls)	438	285	53%
Boe (6:1)	5,251	4,627	13%
Annual per 1,000 Units ⁽³⁾	116	128	(10%)
Production by Commodity			
Oil (bbls)	410,267	507,489	(19%)
Natural Gas (MMcf)	8,079	6,464	25%
Natural Gas Liquids (bbls)	159,681	104,000	53%
Average Prices			
Oil (per bbl)	42.14	33.99	24%
Natural Gas (per Mcf)	6.63	6.35	4%
Natural Gas Liquids (per bbl)	36.41	36.07	1%
Per Boe			
Operating Netback	23.03	24.04	(4%)
Operating Costs	7.24	5.29	37%
G&A Expense	1.26	1.30	(3%)
Well Participations			
Gross	46	56	(18%)
Net	27.2	31.7	(14%)
Net Success	87%	81%	7%
Reserves – Proved plus Probable⁽⁴⁾			
Oil (Mbbls)	3,364	3,368	—
Natural Gas (MMcf)	65,631	58,519	12%
Natural Gas liquids (Mbbls)	725	537	35%
Equivalent (Mboe)	15,028	13,658	10%

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(2) Certain items were negatively impacted, when compared to the prior year, in part due to the Trust having received less than all of the assets of TUSK Energy Inc. after the re-organization.

(3) Includes units and exchangeable shares.

(4) Reserves are based on total proved plus probable working interest reserves prior to deduction of royalties as defined in NI 51-101.

MESSAGE TO UNITHOLDERS



We are pleased to report on the first year-end for TKE Energy Trust. The Trust was formed November 2, 2004 under a Plan of Arrangement which re-organized TUSK Energy Inc. into the Trust and an exploration company. Accordingly, the portion of the 2004 fiscal year as a Trust was short and the information provided in this report, presented here as a continuity of interest, combines these two months as a trust with the first ten months of the year as an exploration and production company.

The decision to become a trust was made in August, 2004 after examination of various alternatives for maximizing value for stakeholders. The principal concerns prior to that time were the size of the Trust (ie. levels of production and reserves) and the long-term sustainability of distributions. We are pleased to report that the former does not seem to be a significant impediment to the formation or operation of a Trust and the latter, as discussed below, appears to be secure.

Sustainable Distributions

An important early decision for the board of directors of the Trust was the determination of the level of distributions. The most critical consideration was to insure that distributions would be, in the opinion of the board and management, sustainable for the foreseeable future. Initial distributions were set at \$0.12 per unit per month (\$1.44 per unit annualized) after an analysis of the tax situation of TUSK Energy Inc. and after consideration of the estimates of cash flow and production for the 2005 fiscal year of approximately \$40 million and 4,500 boepd respectively.

The first distribution was made on January 17, 2005 to holders of units as of December 31, 2004. Unitholders are reminded that a portion of this distribution is taxable as 2004 income.

Payout Ratio

Based upon the projection of production and cash flow for the 2005 fiscal year the aggregate distributions per annum are expected to represent approximately 70 percent of anticipated cash flow.

Commodity Mix

Natural gas represented 70 percent of total production of the Trust and the predecessor company during the 2004 fiscal year and is expected to represent approximately the same percentage of total Trust production during 2005 based upon budgeted levels of production.

Reserve Life Index

The reserve life index ("RLI"), based upon projected production rates for the 2005 fiscal year of 4,500 boepd and the 2004 year-end proved and probable reserves of 15,028 Mboe is approximately 9.15 years.

Building for the Future

TKE has a portfolio of quality properties, the foundation upon which a larger and a stronger energy trust can be built. Development work will focus on our Northeast and Northern (Gage) areas. In the Northeast area, the Trust has access to more than 320 square miles of land in a shallow, multi-zone, gas area where the Trust and its predecessor company have drilled 30 successful gas wells since January, 2003. In the Gage area, the Trust participated in 14 wells during the latter part of 2004, participated in the construction of a central battery facility and pipelines in the first quarter of 2005 and will participate in the drilling of infill wells to further develop the field and in exploration wells on similar prospects in the area during the balance of the 2005 fiscal year.

Strong Balance Sheet

To facilitate future growth TKE did a financing which closed on March 23, 2005. The issue of 2.9 million trust units at a price of \$10.95 raised gross proceeds of \$31,755,000. Subsequent to the closing, our balance sheet is in excellent shape with approximately \$16 million in net debt, a very low debt to cash flow ratio and more than \$30 million in available credit. Balance sheet strength gives the Trust the flexibility to expand its drilling effort and to pursue accretive acquisitions.

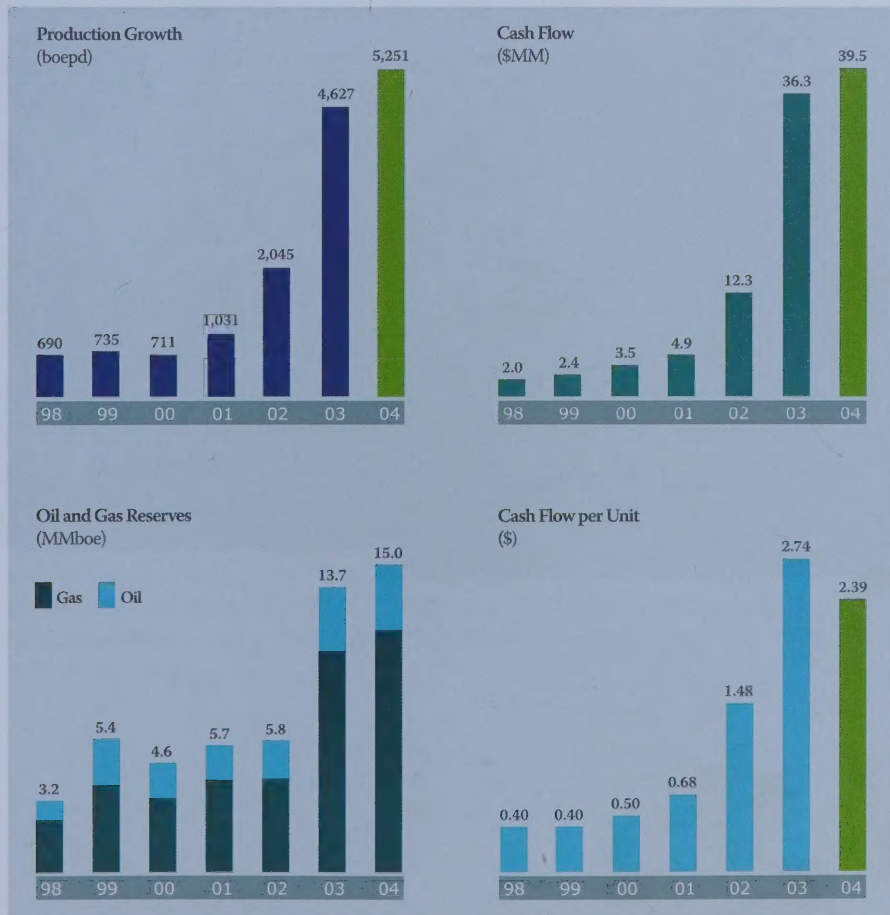
The launch and ongoing success of TKE required considerable effort from a skilled and dedicated corps of employees. Their perseverance and commitment was a key factor in our past success as an E&P company and their work ethic and ability will be an important component in the continued delivery of sustainable and consistent distributions in the future. The Trust has been greatly assisted from its onset by a talented board of directors, many of whom were not involved with the predecessor company.

On behalf of the Board of Directors

"signed"

Norman W. Holton
Chairman

April 20, 2005



A photograph of an industrial facility, likely an oil or gas processing plant. The image shows large, cylindrical storage tanks on the left, and a complex network of large, silver-colored metal pipes and smaller blue pipes on the right. A prominent green cylindrical tank is visible in the lower center. The sky is blue with some light clouds. The title text is overlaid on a white rectangular background in the upper right portion of the image.

EXPLORATION & OPERATIONS REVIEW

Highlights

- production increased 13% over 2003 to average 5,251 boepd in 2004;
- active program with participation in 46 wells (27.2 net);
- substantial development at Gage with 14 wells drilled;
- discovered Kiskatinaw gas at Dunvegan;
- continued long-life gas development at Columbia with two wells;
- drilled thirteen shallow gas wells in Northeast focus area;
- continued development of Hartaven with 5 horizontal oil wells;
- developed and started land acquisition on four Gage-type plays in Northern focus area;
- net drilling success in excess of 87%.

Drilling Activity

Drilling activity has expanded over the past several years reflecting the consistent growth in both cash flow and production. In 2004 TKE continued its track record as a successful driller with participation in 46 wells as shown below.

2004 program	Gross	Net
Oil	19	11.00
Gas	21	12.21
Service	1	0.50
Dry	5	3.50
Total	46	27.21

Program year	Gross	Net	Success %
2000	21	6.4	73
2001	30	12.0	92
2002	29	13.2	84
2003	56	31.7	81
2004	46	27.2	87

Production

Average production during the year was 5,251 boepd. Of this amount 70% was natural gas, 8% was natural gas liquids, 22% was oil with less than 1% being heavy oil. The ten producing areas shown in the table represented approximately 88% of the total production of the Trust during the year ended December 31, 2004 and approximately 85% of the Trust's proved reserves and 83% of proved plus probable reserves.

PRODUCTION BY AREA

Year Ended December 31, 2004

	Oil (bopd)	Gas (Mcf/d)	NGLs (bpd)	Total (boepd)
Alberta				
Columbia	1	688	27	143
Gage	84	627	16	204
Meekwap	80	54	5	95
Pembina	215	837	12	367
Saddle Lake	—	3,926	—	654
Siksika	5	3,222	20	562
Shane	—	6,504	322	1,407
Thorhild	—	2,256	—	376
Whitefish Lake	—	1,439	—	240
Saskatchewan				
Hartaven	597	—	—	597
Other	142	2,581	36	606
Total	1,124	22,134	438	5,251

Production has grown consistently over the past years. Average 2004 production represents a 13% increase in daily boe production over the levels of 2003 with a 7% decrease in oil production, a 53% increase in NGL production and a 25% increase in gas production.

Focus Areas

The production and development activities of TKE occur in five general areas. Production data represents the Trust's share of sales volumes before deduction of royalties.

Northeast

Three of the principal properties of TKE are located in the Northeast area which is located in Alberta to the northeast of the City of Edmonton. This shallow gas area represented approximately 24% of production during the 2004 fiscal year. TKE participated in a total of 14 wells (7.95 net) in this area during the year, 13 of which (7.90 net) were cased as gas wells and one of which (0.05 net) was cased as an oil well. The principal areas of activity are at Saddle Lake, Thorhild/Radway and Whitefish Lake. Each of these areas is summarized below. TKE operates essentially all of its production and drilling activities in the Northeast focus area.

SADDLE LAKE

This natural gas property is located on the Saddle Lake First Nation, approximately 130 kilometres northeast of Edmonton, Alberta. TKE has a 50% interest in a joint venture with Keyano Pimee Exploration Company Ltd., a company that is owned by the Saddle Lake and Whitefish Lake First Nations.

As of December 31, 2004, the Trust had had interests in a total of 38 (19 net) wells (33 of which were producing and five of which were awaiting tie-in). Average production, net to TKE, was 3,926 Mcfd of natural gas for the year ended December 31, 2004. The average production for 2003 was 3,084 Mcfd of natural gas. Natural gas is produced from sandstone reservoirs in the Viking, Colony, Sparky and Clearwater formations. Well depths are in the range of 650-700 metres. The Trust operates all the wells and two compressor/dehydrator stations, which handle approximately 85% of total production.

The balance of the production is compressed at a third-party compressor. Drilling programs of five to seven wells per year are contemplated over each of the next five years or more, depending on results and product markets. This development activity will all take place on existing land holdings.

The Saddle Lake property is comprised of 40,965 gross acres (20,355 net) in lease form and 18,298 gross acres (9,149 net) in permit form. The Trust operated the drilling of seven wells (3.5 net), all of which were gas wells, in this area during the 2004 fiscal year.

THORHILD/RADWAY

The Thorhild/Radway area is located approximately 30 kilometres northeast of Edmonton, Alberta. TKE has interests in 91,520 gross (59,630 net) acres for an average working interest of 65%.

All production from this area is sweet natural gas. Wells are generally less than 900 metres in depth, with production occurring in multiple zones, including the Wabamun, Ellerslie, Glauconitic, Sparky and Second White Specks. TKE is the operator of most of the wells in this area. Development activities include re-completion in shallower zones as deeper horizons decline and step-out drilling, both of which are ongoing. TKE drilled three wells (2.90 net), all of which were gas wells, in this area during 2004.

As of December 31, 2004, TKE had interests in 84 gross (45.8 net) wells, 51 (30.0 net) of which were producing. Average production, net to the Trust, for the year ended December 31, 2004 was 2,256 Mcfd. TKE has interests in four compressor stations, two of which are operated.

WHITEFISH LAKE

This property is located approximately 32 kilometres north of Saddle Lake, within and adjacent to the Whitefish Lake First Nation. TKE has a 50% interest in a joint venture with Keyano Pimée Exploration Company Ltd., a company that is owned by the Saddle Lake and Whitefish Lake First Nations. Whitefish Lake contains five producing natural gas wells which began producing in May 2002 and five shut-in natural gas wells awaiting tie-in. Average production, net to the Corporation, was 1.4 MMcfd for the year ended December 31, 2004 from the five producing wells. Natural gas is produced from sandstone reservoirs in the Colony, Clearwater and Wabasca formations. Well depths are in the range of 540-630 metres. The Trust operates all the wells and a compressor/dehydrator station that serves all the production.

The Whitefish Lake property is comprised of 12,791 gross (6,395 net) acres in lease form. TKE operated the drilling of two wells (1.0 net), each of which was a gas well, during 2004.

Saskatchewan

The Saskatchewan area includes only one principal property which is located in the southeast part of the province. TKE participated in the drilling of five wells (2.80 net), all of which were horizontal oil wells, during the 2004 fiscal year.

HARTAVEN

The Hartaven property, located in southeast Saskatchewan approximately 130 kilometres southeast of Regina, is the Trust's largest oil producing property, generating approximately 53% of oil production or 11% of total boe in 2004. As of December 31, 2004, the Corporation had 45 (21.5 net) wells, 40 (19.5 net) of which were producing, including the five horizontal wells (2.8 net) drilled in 2004. Average production, net to the Trust, was 597 bopd for the year ended December 31, 2004. Hartaven has been a very active property since 2000, when it produced an average of 10 bopd. It is anticipated that up to eight wells will be drilled in 2005, including a Frobisher zone development program. The Hartaven property is comprised of 2,611 gross (1,297 net) acres.

Northern

The Northern areas principal producing properties include Gage, Shane and Meekwap, each of which is located in Alberta. The Trust also holds a 17 percent interest in an oil producing unit at Inga, B.C. The focus of development and exploration activity during the 2004 fiscal year was on the Gage property, on prospects similar to Gage which will be drilled during the 2005 fiscal year and on the development of a new gas discovery at Dunvegan. TKE drilled 20 wells (12.32 net) in the Northern focus area during the 2004 fiscal year. Of these 14 wells were drilled at Gage resulting in 12 oil wells, one gas well and one dry hole. The interest of TKE in these wells as of the end of the 2004 fiscal year, after giving consideration to the re-organization which took effect on November 2, 2004, was 5.5 net oil wells, 0.25 net gas wells and 0.50 net dry holes.

GAGE AREA

The Gage area is located approximately five kilometres northwest of Fairview, Alberta. TKE has interests in a total of 13,952 gross (6,528 net) acres, for an average working interest of 47%.

Production at Gage is from the Montney formation (oil and solution gas) and the Gething formation (gas). At year end 2004, the Trust had interests in 12 oil wells (6 net), two gas wells (0.75 net) and two (1 net) disposal wells. Ten of the oil wells and one of the gas wells were on production at year end with the production of the oil wells restricted by an MRL.

Production gathering and treatment facilities for the handling of both natural gas and liquids are essentially complete and will be commissioned shortly. This will enable production from currently non-producing wells and allow for conservation of natural gas currently being flared from some of the wells. After the facility is operational applications will be made for an increase in the allowable production rate applicable to many of the wells.

As of December 31, 2004 application had been made for a "holding" applicable to about one-third of the defined field area for Montney oil and similar applications will be made for the balance of the field area during the first half of 2005 so that infill drilling can occur. Up to 7 more wells (2.3 net) are planned for 2005 for development and implementation of down-spacing. Wells are typically 1,200 metres in depth. Average production, net to the Trust, for the year ended December 31, 2004 was 627 Mcfd of natural gas, 16 bpd of NGL and 84 bopd (204 boepd). The Gage property was split equally between TKE and TUSK Energy Corporation when the re-organization was finalized on November 2, 2004. Exit rate production, net to TKE, from the Gage property was 227 boepd.

SHANE

The Shane property, located approximately 70 kilometres northwest of Grande Prairie, Alberta, was the site of a significant gas and NGL discovery in the first quarter of 2001. TKE owns a 27.7% working interest in the pool. This high deliverability pool produces its reserves relatively quickly and production was characterized by a high decline rate.

As of December 31, 2004, TKE owned interests in five (1.6 net) wells at Shane, three of which were producing. The average net production for the year ended December 31, 2004 was 6.5 MMcfd of natural gas and 322 bpd of NGLs from three producing wells. Average NGL production during the period ended December 31, 2004 was 50 barrels per MMcf of gas. The Shane property is comprised of 8,800 gross (2,930 net) acres.

MEEKWAP

Meekwap is located approximately 200 kilometres northwest of Edmonton, Alberta. The Trust's interests in the Meekwap area include a 10% interest in the Meekwap D-2A Unit No. 1, a 0.875% net profits interest in unit production and working interests varying from 5% to 50% in non-unitized lands. Meekwap is operated by a third party. The property consists of 7,040 gross (2,948 net) acres. This area produced an average net production of 86 bopd of light oil and NGL and 54 Mcfd of natural gas in the year ended December 31, 2004.

West-Central Alberta

The Trust's West-Central area is principally located north of the City of Calgary, south of the City of Edmonton and west of the 5th meridian. The principal properties are at Pembina (light oil production, shallow gas and CBM potential) and Columbia (deep long-life natural gas).

PEMBINA AREA

The Pembina area properties are located in west-central Alberta, between Townships 42 and 52 and Ranges 4 and 12 W5M. The centre of this large area lies approximately 100 kilometres southwest of Edmonton, Alberta. TKE has an average 71% working interest in 30,808 gross (23,149 net) acres with working interests that vary from less than 10% to 100%. Most of the production is operated by the Trust.

Light oil production is from the Cardium formation at a depth of approximately 1,600 metres and from the Belly River zone at approximately 600 metres. Shallow gas production is from both the Edmonton and Scollard sands. Reserves in the area are typically long-life with a low decline. As of December 31, 2004, the Trust held interests in 220 (106.7 net) wells, 118 (65.3 net) of which were producing. Average production, net to the Trust, was 367 boepd for the year ended December 31, 2004.

A number of the Cardium wells have penetrated shallow gas zones that are continuing to be evaluated and tested and the waterflood of the new Norbuck Belly River Unit (TKE 89.9%) will be initiated this summer.

COLUMBIA

The Columbia area is located in west-central Alberta, approximately 140 kilometres southwest of Edmonton, Alberta. There are 14 (2.0 net) producing gas wells of non-operated production. Working interests in this area vary from 5% to 42%. The production produces to either of two third-party compressor stations depending on markets. The low decline production, generally with decline rates of less than 10% per annum, is from the Viking and Cardium formations at depths in excess of 2,000 metres. Many of the wells are dual producers. TKE has 12,480 gross (2,247 net) acres of land. Two gas wells (0.52 net) were drilled in 2004. Average production, net to the Trust, for the year ended December 31, 2004, was 688 Mcfd of natural gas and 27 bpd of natural gas liquids.

Southern

The Southern area is located entirely in the Province of Alberta to the east and southeast of the City of Calgary. The principal property in this area is located at Siksika.

SIKSIKA

Siksika is located on the Siksika First Nation, approximately 65 kilometres southeast of Calgary, Alberta. The property is operated by a third party. As of December 31, 2004, TKE had a 42% average working interest in 10,602 gross (4,412 net) acres containing eight (4.2 net) producing wells and four (1.8 net) wells that are currently shut-in. Production is mainly from the Glauconitic formation. Average production, net to the Trust, was 3,222 Mcfd of natural gas and 25 bpd of oil for the year ended December 31, 2004.

RESERVES

The reserves of TKE were evaluated effective as of January 1, 2005 in a report (the "TKE Report") prepared by Chapman Petroleum Engineering Ltd. ("Chapman"), an independent reservoir engineering firm. The TKE Report has been prepared in accordance with the standards of disclosure for independent evaluations mandated in National Instrument 51-101. Under NI 51-101, proved reserves (1P) are defined as having a 90% probability that the actual reserves ultimately recovered will equal or exceed the proved reserves estimated. Probable reserves (2P) are defined under NI 51-101 as reserves with a 50% probability that the actual reserves ultimately recovered will be less than or greater than the proved plus probable reserves estimate.

Using the NI 51-101 definitions, the TKE Report assigns the following reserve estimates based on forecast price and cost assumptions as of January 1, 2005.

Summary of Oil and Gas Reserves

January 1, 2005

(as of December 31, 2004)

FORECAST PRICES AND COSTS

Reserves Category	Reserves							
	Light and Medium Oil		Heavy Oil		Natural Gas ⁽¹⁾		Natural Gas Liquids	
	Gross (mdbl)	Net (mdbl)	Gross (mdbl)	Net (mdbl)	Gross (mmcf)	Net (mmcf)	Gross (mdbl)	Net (mdbl)
Proved Developed Producing	1,326	1,146	7	7	23,431	18,884	318	222
Proved Developed Non-Producing	78	67	32	30	10,082	8,097	38	28
Proved Undeveloped	—	—	—	—	150	123	—	—
Total Proved	1,405	1,212	39	37	33,664	27,104	356	249
Probable	1,770	1,409	151	124	31,967	25,496	370	255
Total Proved Plus Probable	3,174	2,621	190	161	65,631	52,600	725	504

(1) Includes associated, non-associated and solution gas where applicable.

Gross reserves are the Trust's share of reserves and net reserves are gross reserves after deduction for crown, freehold and other royalties. Volumes may not add due to rounding. Approximately 73% of total 2P reserves are natural gas, 21% are light and medium oil and 5% is natural gas liquids. A very minor amount (1%) of total 2P reserves are heavy oil.

Reserve Reconciliation

A reconciliation of the reserve estimates, after royalties, as of the end of the 2004 fiscal year with the reserves reported in the annual report for the year ended December 31, 2003 is presented below.

Reconciliation of Changes in Oil and Gas Reserves

January 1, 2005

(as of December 31, 2004)

FORECAST PRICES AND COSTS

	Light and Medium Oil (mbbl)		Heavy Oil (mbbl)		NGLs (mbbl)		Assoc. & Non-Assoc. Gas ⁽¹⁾ (mmcf)		Solution Gas (mmcf)		Total (mboe)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved												
Reserves, January 1, 2004	1,407	1,219	44	41	309	209	30,757	24,170	1,600	1,247	7,153	5,705
Production	(404)	(346)	(6)	(5)	(160)	(66)	(7,851)	(5,838)	(228)	(170)	(1,917)	(1,418)
Acquisitions & Dispositions	(182)	(136)	—	—	(2)	(2)	(681)	(297)	(244)	(204)	(338)	(222)
Discoveries	513	406	—	—	34	25	2,982	1,938	390	325	1,109	808
Extensions	—	—	—	—	106	72	4,520	3,647	—	—	859	680
Revisions	71	69	1	1	69	11	2,248	2,156	171	130	544	462
Reserves, January 1, 2005	1,405	1,212	39	37	356	194	31,975	25,776	1,689	1,328	7,411	6,015
Probable												
Reserves, January 1, 2004	1,764	1,445	153	127	228	154	24,383	19,221	1,779	1,688	6,505	5,211
Production	—	—	—	—	—	—	—	—	—	—	—	—
Acquisition & Disposition	(98)	(63)	—	—	(2)	(2)	(736)	(388)	(184)	(153)	(253)	(155)
Discoveries	277	216	—	—	41	29	4,286	2,587	287	239	1,080	716
Extensions	—	—	—	—	105	71	3,287	2,694	—	—	653	520
Revisions	(173)	(189)	(3)	(3)	(2)	3	(904)	(742)	(231)	(350)	(367)	(254)
Reserves, January 1, 2005	1,770	1,409	150	124	370	255	30,316	23,372	1,651	2,124	7,618	6,037
Proved plus Probable												
Reserves, January 1, 2004	3,171	2,664	197	168	537	363	55,140	43,391	3,379	2,935	13,658	10,916
Production	(404)	(346)	(6)	(5)	(160)	(66)	(7,851)	(5,838)	(228)	(170)	(1,917)	(1,418)
Acquisition & Disposition	(280)	(199)	—	—	(4)	(4)	(1,417)	(685)	(428)	(357)	(592)	(377)
Discoveries	790	622	—	—	75	54	7,268	4,525	677	564	2,189	1,524
Extensions	—	—	—	—	211	143	7,807	6,341	—	—	1,512	1,200
Revisions	(103)	(120)	(1)	(2)	66	14	1,344	1,414	(60)	480	176	208
Reserves, January 1, 2005	3,174	2,621	190	161	725	504	62,291	49,148	3,340	3,452	15,028	12,053

(1) Gas produced from gas wells.

Proved (1P) boe reserves in the TKE Report are 4% higher than the prior year. Reserves of oil and natural gas liquids are up 2% while reserves of natural gas are 4% higher than the prior year. Proved plus probable (2P) reserves increased over the levels of the prior year with boe reserves up 9%, reserves of oil and NGLs up 5% and reserves of natural gas up 12%.

Summary of Net Present Values

The following table summarizes the net present value at a 10% discount factor before tax of the reserves evaluated in the TKE Report based upon forecast prices and cost assumptions.

Net Present Values of Future Net Revenue

January 1, 2005

(as of December 31, 2004)

FORECAST PRICES AND COSTS

Reserves Category	Net Present Values of Future Net Revenue ⁽¹⁾				
	Before and After Income Taxes Discounted at (%/Year) ⁽²⁾				
	0	5	10	15	20
	(\$000s)	(\$000s)	(\$000s)	(\$000s)	(\$000s)
Proved Developed Producing	110,253	93,545	82,148	73,778	67,320
Proved Developed Non-Producing	35,374	23,777	17,801	14,210	11,821
Proved Undeveloped	426	291	209	157	122
Total Proved	146,053	117,614	100,158	88,145	79,263
Probable	150,163	95,975	68,476	52,285	41,780
Total Proved plus Probable	296,216	213,588	168,635	140,431	121,043

(1) Includes ARTC.

(2) After Income Tax values are the same as Before Income Tax values due to the flow-through of income tax attributes to Unitholders under the structure of the Trust.

Pricing Assumptions

The following tables detail the benchmark reference prices for the regions in which the Trust operated as at December 31, 2004 reflected in the reserves data disclosed above under "Statement of Reserves Data and Other Oil and Gas Information – Disclosure of Reserves Data". The pricing assumptions were provided by Chapman.

Summary of Pricing and Inflation Rate Assumptions

January 1, 2005

(as of December 31, 2004)

FORECAST PRICES AND COSTS

Year	Oil				Natural Gas	Edmonton Liquids Prices					Exchange Rate ⁽²⁾
	WTI Cushing OK (\$US/bbl)	Edmonton Par Price 40° API (\$Cdn/bbl)	Hardisty Heavy 12° API (\$Cdn/bbl)	Cromer Medium 29.3° API (\$Cdn/bbl)	AECO Gas Price (\$Cdn/mmbtu)	Propane (\$Cdn/bbl)	Butane (\$Cdn/bbl)	Pentanes Plus (\$Cdn/bbl)	NGL Mix (\$Cdn/boe)	Inflation Rates ⁽¹⁾ %/Year	
Forecast											
2005	42.00	50.22	35.15	46.64	6.55	30.21	36.58	51.53	38.52	0.0	0.82
2006	40.00	49.00	34.30	45.51	6.30	29.48	35.69	50.28	37.58	1.5	0.80
2007	38.00	47.72	33.40	44.32	5.80	28.71	34.76	48.96	37.63	1.5	0.78
2008	36.00	45.15	31.61	41.94	5.55	27.16	32.89	46.33	36.60	1.5	0.78
2009	35.00	43.87	30.71	40.75	5.63	26.39	31.96	45.02	34.63	1.5	0.78
2010	35.53	44.54	31.18	41.37	5.71	26.80	32.45	45.71	33.65	1.5	0.78
2011	36.06	45.23	31.66	42.01	5.79	27.21	32.94	46.41	34.69	1.5	0.78
2012	36.60	45.92	32.15	42.65	5.87	27.63	33.45	47.12	35.22	1.5	0.78
2013	37.15	46.63	32.64	43.31	5.96	28.05	33.96	47.84	35.76	1.5	0.78
2014	37.70	47.34	33.14	43.97	6.04	28.48	34.48	48.58	36.31	1.5	0.78
2015	38.27	48.06	33.65	44.64	6.13	28.92	35.01	49.32	36.87	1.5	0.78
2016	38.84	48.80	34.16	45.33	6.21	29.36	35.55	50.07	37.43	1.5	0.78
2017	39.43	49.55	34.68	46.02	6.30	29.81	36.09	50.84	38.00	1.5	0.78
2018	40.02	50.31	35.21	46.72	6.39	30.26	36.64	51.62	38.58	1.5	0.78
2019	40.62	51.08	35.75	47.44	6.48	30.73	37.20	52.41	39.17	1.5	0.78
2020	41.23	51.86	36.30	48.16	6.58	31.20	37.77	53.21	39.77	1.5	0.78
Thereafter	41.23	51.86	36.30	48.16	6.58	31.20	37.77	53.21	39.77	0.0	0.78

(1) Inflation rates for forecasting prices and costs.

(2) Exchange rates used to generate the benchmark reference prices in this table.

Reserve Life Index

The reserve life index is calculated effective as of the end of the 2004 fiscal year, based on reserves and production net to the Trust's interest and net of royalties. The reserve life index for proved plus probable reserves as of the end of the 2004 fiscal year was 9.1 years compared to 8.1 years for 2003 calculated using the annualized production for the fourth quarter.

PROVED PLUS PROBABLE

	2004	2003
Crude Oil & NGLs	8.2	6.4
Natural Gas	9.5	9.1
Boe	9.1	8.1

For the purposes of the calculation, heavy oil has been included in crude oil & NGLs. Heavy oil is an insignificant component of overall liquids production representing less than 1%. Natural gas liquid represents 17% of all liquids volumes.

Reserve Replacement Ratio

As TKE continued to grow in 2004, discoveries, extensions and revisions replaced production by 206% on a boe basis.

	Proved Plus Probable
Crude Oil & NGLs	1.87
Natural Gas	2.11
Boe	2.06

Recycle Ratio

2004	
Operating Netbacks (\$/boe)	20.59
Current Year FD&A Costs Proved plus Probable (\$/boe)	10.60
Recycle Ratio	1.94

Finding, Development and Acquisitions Costs

NI 51-101 specifies how finding and development ("F&D") costs should be calculated if reported. NI 51-101 required that the exploration and development costs incurred in the year be aggregated with the change in estimated future development costs and then divided by applicable reserve additions. The calculation specifically excludes the effects of acquisitions and dispositions on both reserves and costs. By excluding the effects of acquisitions and dispositions TKE believes that the provisions of NI 51-101 do not fully reflect ongoing reserve replacement costs. Since acquisitions can have a significant impact on the annual reserve replacement costs of TKE the exclusion of these amounts results in an inaccurate portrayal of the cost structure of TKE. Accordingly, TKE will also report finding, development and acquisition ("FD&A") costs that will incorporate all acquisitions net of any dispositions during the year.

The calculations of F&D costs and FD&A costs are noted in the table below. The calculations are based on the net reserves of TKE.

	2004	2003	2002	Three Year Average per boe
Finding and Development Costs				
Land	\$ 4,420,563	\$ 3,005,678	\$ 1,164,697	
Seismic and Other Exploration Costs	3,034,090	4,657,731	2,298,099	
Drilling & Completion	25,263,299	18,094,027	7,911,474	
Total	32,717,952	25,757,436	11,374,270	
On Stream	4,816,213	4,902,446	3,048,069	
Total	37,534,165	30,659,882	14,422,339	
Change in Future Costs between Years				
Proved plus Probable	3,585,000	6,735,000	(5,270,000)	
Adjusted Finding and Development Costs	\$ 41,119,165	\$ 37,394,882	\$ 9,152,339	
Boe Reserve Additions Net of Revisions (before royalties)	3,877,000	2,566,000	822,000	
Finding and Development Costs per boe	\$ 10.60	\$ 14.57	\$ 11.13	\$ 12.10
Acquisition Costs				
Costs of Acquisitions	\$ —	\$ 63,284,691	\$ —	
Net Reserves Acquired, 2P (boe)	—	5,862,000	—	
Acquisition Costs per boe	\$ —	\$ 10.80	\$ —	
Finding, Development and Acquisition Costs per boe	\$ 10.60	\$ 11.95	\$ 11.13	\$ 11.23

Asset Value Per Trust Unit and Exchangeable Share

Net asset per Trust unit and exchangeable share was \$7.53 as of December 31, 2004. Undeveloped land and seismic data valuations are based upon the estimated fair market value as of year end. Reserves values are presented on a before tax basis and the calculation does not include any reflection of future tax liabilities.

December 31, 2004

(\$ except Unit Information)

Assets

Working Capital (Deficiency)	\$ (10,308,049)
Proved and Probable Reserves (@ 10% DCF BTAX, Forecast Price & Costs)	168,635,000
Undeveloped Land (92,434 Net Acres)	6,233,000
Seismic Data	2,364,000
	166,923,951

Liabilities

Bank Indebtedness	(33,670,000)
Obligations Under Capital Lease	(310,212)
Net Asset Value	\$ 132,943,739
Trust Unit and Exchangeable Shares Outstanding December 31, 2004	17,664,573
NAV per Trust Unit and Exchangeable Share	\$ 7.53

A low-angle, upward-looking photograph of several modern skyscrapers with glass and steel facades. The buildings are set against a clear blue sky. The perspective creates a sense of height and architectural grandeur. A semi-transparent white rectangular box is centered over the middle of the image, containing the title text in blue.

MANAGEMENT'S DISCUSSION & ANALYSIS

The following analysis and discussion is provided by the management of TKE Energy Trust ("TKE" or the "Trust") and should be read in conjunction with the audited consolidated financial statements for the year ended December 31, 2004 and 2003.

Basis of Presentation – The financial data presented below has been prepared in accordance with Canadian generally accepted accounting principles. The reporting and the measurement currency is the Canadian dollar.

Non-GAAP Measurements – The Management's Discussion and Analysis contains the term cash flow from operations, which should not be considered an alternative to, or more meaningful than cash flow from operating activities as determined in accordance with Canadian generally accepted accounting principles as an indicator of the Trust's performance. The Trust's determination of cash flow from operations may not be comparable to that reported by other companies. The reconciliation between net earnings and cash flow from operations can be found in the consolidated statements of cash flows in the unaudited interim consolidated financial statements and the audited consolidated financial statements. The Trust also presents cash flow from operations per unit whereby per unit amounts are calculated using weighted average shares outstanding consistent with the calculation of earnings per unit.

Boe Presentation – Barrels of oil equivalent may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf: 1 bbl of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. All boe conversions in this report are derived by converting gas to oil in the ratio of six thousand cubic feet of gas to one barrel of oil.

Plan of Arrangement – Conversion to a Trust

TKE Energy Trust ("TKE" or the "Trust") is an open-ended, unincorporated investment trust governed by the laws of the province of Alberta. The Trust as established as part of a Plan of Arrangement (the "Arrangement") that became effective on November 2, 2004.

The reorganization resulted in the shareholders of TUSK Energy Inc. receiving trust units or exchangeable shares in the Trust, a new energy trust that owns approximately 95 percent of the assets of TUSK Energy Inc. In addition, the shareholders of TUSK Energy Inc. received shares in a separate, publicly-listed, exploration-focused company TUSK Energy Corporation ("TUSK"). The remaining properties were transferred to TUSKEx.

Pursuant to the Arrangement, shareholders of TUSK Energy Inc. received shares of TUSKEx and at their election, either units of the Trust, which will pay monthly cash distributions or exchangeable shares which may be exchanged into units of the Trust. The Arrangement resulted in TUSK Energy Inc. shareholders receiving one trust unit or exchangeable share of the Trust and one of a share in TUSKEx for every two shares of TUSK Energy Inc.

As part of the Arrangement, the Trust put in place new credit facilities totaling \$47.5 million to replace existing debt.

Upon completion of the Arrangement, 15.9 million trust units and 1.8 million exchangeable shares were outstanding.

The conversion of TUSK Energy Inc. to a Trust has been accounted for as a continuity of interest. Accordingly, the consolidated financial statements for 2004 reflect the financial position, results of operations and cash flows as if the Trust had always carried on the business formerly carried on by TUSK Energy Inc. The year ended December 31, 2004 reflects the results of operations and cash flows of TUSK Energy Inc. and its subsidiaries for the period January 1 to November 1, 2004 and the results of operations and cash flows of the Trust and its subsidiaries for the period November 2 to December 31, 2004. The comparative figures are the results of TUSK Energy Inc. and its subsidiaries. Due to the conversion into an energy trust, certain information included in the financial statements for prior periods may not be directly comparable.

The term “units” has been used to identify both the Trust units and exchangeable shares of the Trust issued on or after November 2, 2004 as well as the common shares of the corporation outstanding prior to the conversion on November 2, 2004.

Summary of Information per Boe

	Year Ended December 31 2004 (\$)	Year Ended December 31 2003 (\$)
Gross Revenue	39.99	36.66
Royalties, Net of ARTC	9.72	7.33
Net Revenue	30.27	29.33
Operating Expense	7.24	5.29
Net Operating Revenue	23.03	24.04
General & Administrative	1.26	1.30
Interest Expense	1.06	1.16
Capital Taxes	0.12	0.11
Cash Flow per boe	20.59	21.47

Oil and Gas Revenues

Oil and gas revenue, before royalties, for the year ended December 31, 2004 was \$76,631,065 compared to \$61,906,862 for the year ended December 31, 2003 — a 24% increase. This was due to an \$8.12 per barrel increase in the average oil price, a \$0.27 per mcf increase in the average price of natural gas and an increase of 13% in boe production from 1,688,876 boe in 2003 to 1,916,442 in 2004.

	Year Ended December 31 2004	Year Ended December 31 2003
Oil and Gas Revenues, Before Royalties	\$ 76,631,065	\$ 61,906,862
Oil Production (bbls)	410,267	507,489
Oil Price (\$/bbl)	\$ 42.14	\$ 33.99
NGL Production (bbls)	159,681	104,000
NGL Price (\$/bbl)	\$ 36.41	\$ 36.07
Gas Production (MMcf)	8,079	6,464
Gas Price (\$/Mcf)	\$ 6.63	\$ 6.35
Boe Production	1,916,442	1,688,876
Boe per Day	5,251	4,627

2004 AND 2003 ANNUAL PRODUCTION BY FIELD

	2004			2003		
	Oil	Gas	NGL	Oil	Gas	NGL
Columbia	358	251,005	9,998	303	164,842	2,356
Gage	30,709	228,929	5,736	1,322	360,230	7,176
Hartaven	217,941	—	328,048	—	—	—
Saddle Lake	—	1,432,973	19	45	1,125,751	—
Shane	—	2,374,248	117,680	—	2,374,453	91,753
Siksika	1,951	1,176,195	7,307	5,495	677,990	—
Thorhild & Radway	—	823,335	1	—	461,329	—
Whitefish	—	525,366	19	—	544,437	—
Other	159,308	1,266,911	18,921	172,276	755,292	2,715
Total	410,267	8,078,962	159,681	507,489	6,464,324	104,000

Royalties

Total royalties, net of ARTC, were \$18,618,312 (\$9.72 per boe) for the year ended December 31, 2004 compared to \$12,372,279 (\$7.33 per boe) for the year ended December 31, 2003. Royalty rates increased with commodity prices. Net royalties represented 24.0% of gross revenues in 2004 compared to 20.0% in 2003. Net royalties as a percentage of gross revenues was higher due to the end of horizontal royalty free periods at several wells at Hartaven and the high royalty burden at Shane due to the high productivity of the wells. Alberta Royalty Tax Credit was \$573,895 for the year, higher than the \$500,000 maximum due to the successful appeal of a Notice of Assessment resulting in the refund of \$73,895 of ARTC.

	Year Ended December 31 2004 (\$)	Year Ended December 31 2003 (\$)
Crown Royalties	10,953,662	7,098,924
Indian Oil & Gas Canada Royalties	5,060,394	3,467,264
Freehold Royalties	912,155	1,196,274
Saskatchewan Production Tax	579,489	775,980
Gross Overriding Royalties	1,686,507	618,334
	19,192,207	13,156,776
Alberta Royalty Tax Credit	(573,895)	(784,497)
Net Royalties	18,618,312	12,372,279
Net Royalties per boe (6:1)	9.72	7.33
Royalties of Percentage of Revenue	24%	20%

Operating Expenses

Operating expenses in calendar 2004 were \$13,872,852 (\$7.24 per boe) compared to \$8,935,754 (\$5.29 per boe) in fiscal 2003. Operating costs increased on a boe basis due to properties purchased in 2003 which have longer reserve lives but lower productivity which results in higher per boe operating costs. An extensive workover program was undertaken in the Trust's Thorhild and Radway area to optimize production which resulted in increased operating expenses in the second half of 2004.

Depletion, Depreciation and Amortization (DD&A)

Depletion and depreciation was \$29,806,563 for the year ended December 31, 2004, which represents a provision of \$15.55 per boe of production. For the year ended December 31, 2003, the Company recorded a DD&A provision of \$24,773,000 (\$14.67 per boe). The increase in DD&A is due to a very active drilling and development capital program.

General and Administrative

Gross general and administrative costs have increased from \$4,453,303 in 2003 to \$5,156,916 mainly due to the hiring of additional personnel and increases in most G&A expense categories with increased activity. Net general and administrative costs increased 9% compared to a 13% increase in production.

	Year Ended December 31 2004 (\$)	Year Ended December 31 2003 (\$)
Gross General and Administrative	5,156,916	4,453,303
Acquisition, Exploration & Development Costs Capitalized	(1,811,742)	(1,367,500)
Overhead Recoveries	(935,994)	(884,131)
Net General and Administrative	2,409,180	2,201,672
Per boe	1.26	1.30

In conjunction with the Arrangement, the Trust entered into a Technical Services Agreement with TUSKEx where the Trust shares personnel and certain administrative and technical services in connection with the management, development, exploitation and operation of the assets of TUSKEx. The Technical Services Agreement has no set termination date and will continue until terminated by either party with one year prior written notice to the other party or some other date as mutually agreed. The Trust provides these services to TUSKEx on an expense reimbursement basis, based on TUSKEx's monthly capital activity and production levels of both the Trust and TUSKEx. Total expenses reimbursed by TUSKEx and included in G&A expenses above for 2004 were \$245,000.

Provision for Income Taxes

The provision for income taxes for the year ended December 31, 2004 was comprised of \$1,020,000 in future taxes (2003 – \$1,100,000) and \$223,156 related to large corporation tax (2003 – \$176,710). Included in the 2004 amounts is a benefit of \$590,000 related to substantively enacted changes to the provincial income tax rate (2003 – \$2.2 million).

There was no cash income tax provision in 2004 and none is expected in 2005.

Capital Expenditures

Capital additions, excluding acquisitions and divestitures, for the year ended December 31, 2004 were \$37,652,325 compared to \$34,843,843 for the year ended December 31, 2003.

	Year Ended December 31 2004 (\$)	Year Ended December 31 2003 (\$)
Land	4,420,563	6,837,059
Seismic & Exploration	3,034,090	4,657,731
Drilling & Completion	25,263,299	18,112,646
Facilities	4,816,213	4,902,446
Corporate	118,160	333,961
Total	37,652,325	34,843,843

Liquidity and Capital Resources

TKE had a working capital deficiency, before bank indebtedness, of \$10,308,049 at December 31, 2004.

The Trust has a financing arrangement with two Canadian financial institutions whereby the Trust was provided a \$47.5 million revolving production loan of which \$33.7 million was drawn as at December 31, 2004.

On March 1, 2005 the Trust announced that it has entered into an agreement with a syndicate of underwriters to sell 2,900,000 trust units at \$10.95 per unit to raise gross proceeds of \$31,755,000. Net proceeds from the financing will be used to accelerate the trust's ongoing capital programs, repay outstanding borrowing and for general corporate purposes.

On an ongoing basis TKE will typically utilize three sources of funding to finance its capital expenditure program: internally generated cash flow from operations, debt where deemed appropriate and new equity issues if available on favorable terms. When financing corporate acquisitions, TKE may also assume certain future liabilities. Commodity prices and production volumes have the largest impact on TKE's ability to generate adequate cash flow to meet all its obligations. A prolonged decrease in commodity prices would negatively affect TKE's cash flow from operations and would also likely result in a reduction in the amount of bank loan available. If TKE's capital expenditure program does not result in sufficient additional reserves and/or production it would likely have a negative impact on TKE's liquidity.

TKE may adjust its capital expenditure program depending on the commodity price outlook. TKE believes that internally generated cash flow and incremental bank debt should be sufficient to finance current operations and planned capital spending in the next year.

Business Risks

The marketability and price of products owned or that may be acquired or discovered by TKE will be affected by numerous factors beyond the Trust's control. TKE must compete in all aspects of its operations with a number of other corporations that have equal or greater technical or financial resources. The ability of the Trust to market its natural gas may depend on its ability to acquire space in pipelines that deliver natural gas to commercial markets. The Trust is also subject to market fluctuations in the prices of products, exchange rates, uncertainties related to the proximity of its reserves to pipelines and processing facilities and extensive government regulation.

Costless Collars & Puts

The Trust entered into several short term arrangements impacting the selling price of part of its oil and natural gas production applicable to the 2004 fiscal year. These agreements included both costless collars and floor price arrangements. The trust realized a net loss of \$778,103 (compared to a net loss of \$1,478,506 in 2003) on its oil and natural gas risk management program. Additional information with respect to similar arrangements applicable to the 2005 fiscal year is included in Note 12 to the Financial Statements.

Cash Distributions

Management monitors the Trust's distribution payout policy with respect to forecasted net cash flow, debt levels and capital expenditures. TKE expects to distribute approximately 70% of its annual cash flow to unitholders and retain the remaining cash flow for capital expenditures and debt repayment. Exchangeable shares are convertible into trust units of the Trust based on the exchange ratio, which is adjusted monthly to reflect that distributions are not paid on the exchangeable shares and cash flow related to the exchangeable shares it retained by the Trust for additional capital expenditures or debt repayment. The key drivers of TKE's cash flow, as is generally the case with other energy trusts, are commodity prices and production. Since the Trust's production is weighted to natural gas (70 percent in 2004), natural gas prices have a significant effect on its cash flow.

TKE's initial cash distribution declared was \$0.12 per trust unit for the month of December. The Trust has maintained this cash distribution per unit for the first quarter of 2005.

Quarterly Data

The following tables set forth selected quarterly financial information for the last eight financial quarters.

	Fourth Quarter 2004	Third Quarter 2004	Second Quarter 2004	First Quarter 2004
Production per Day				
Oil and NGLs (bbls)	1,372	1,548	1,560	1,770
Natural Gas (Mcf)	18,929	22,943	23,650	23,056
Boe	4,527	5,372	5,502	5,612
Netback per boe (\$)	19.33	19.61	22.76	22.30
Petroleum and Natural Gas Sales, Net (\$)	11,834,805	14,820,744	15,963,678	15,393,526
Funds from Operations (\$)	7,125,221	9,690,236	11,393,689	11,262,417
Per Common Unit (basic) (\$)	0.39	0.60	0.70	0.70
Per Common Unit (fully diluted) (\$)	0.39	0.58	0.68	0.68
Net Income (Loss)	(237,413)	835,164	(2,329,955)	2,575,817
Per Common Unit (basic) (\$)	(0.03)	0.06	0.14	0.16
Per Common Unit (fully diluted) (\$)	(0.03)	0.06	0.14	0.16

	Fourth Quarter 2003	Third Quarter 2003	Second Quarter 2003	First Quarter 2003
Production per Day				
Oil and NGLs (bbls)	1,872	1,638	1,717	1,498
Natural Gas (Mcf)	23,416	20,329	15,999	10,759
Boe	5,775	5,026	4,383	3,292
Netback per boe (\$)	16.68	19.50	24.58	28.95
Petroleum and Natural Gas Sales, net (\$)	13,637,220	12,737,001	12,571,439	10,588,923
Funds from Operations (\$)	8,860,103	9,014,351	9,804,608	8,579,914
Per Unit (basic) (\$)	0.48	0.60	0.80	0.86
Per Unit (fully diluted) (\$)	0.46	0.58	0.78	0.84
Net Income	(1,086,997)	1,082,751	6,657,308	3,505,914
Per Unit (basic) (\$)	(0.24)	0.08	0.56	0.36
Per Unit (fully diluted) (\$)	(0.14)	0.08	0.54	0.34

Fourth Quarter Analysis

	Q4 2004	Q3 2004	Q4 2003
Daily Production			
Oil and NGLs, bpd	1,372	1,548	1,872
Natural Gas, Mcfd	18,929	22,943	23,416
Boepd	4,527	5,372	5,775
Summary of Product Prices			
Oil and NGLs per bbl	\$ 43.12	\$ 43.42	\$ 31.31
Gas per MCF	\$ 6.55	\$ 6.66	\$ 5.37
Financial (\$000s, except per Unit data)			
Oil and Gas Revenues	16.7	20.2	16.9
Royalties, Net of ARTC	4.8	5.4	3.3
Oil and Gas Operating	3.8	4.0	3.4
Interest on Long-Term Debt	0.5	0.5	0.6
General and Administrative	0.4	0.7	0.6
Depletion, Depreciation and Accretion	7.2	8.0	11.1
Stock-Based Compensation	2.0	0.3	—
Cash Flow from Operations	7.1	9.7	8.9
Net Income (Loss)	(0.2)	0.8	(1.1)
Per Unit Basic	(0.03)	0.03	(0.24)
Per Unit Diluted	(0.03)	0.03	(0.24)
Capital Expenditures	10.9	8.4	9.7
Net Debt	44.3	44.3	50.0

Oil and Gas Revenues

Oil and gas revenues were \$16.7 million in the fourth quarter of 2004 compared to \$20.2 million in the third quarter of 2004 and \$16.9 million in the fourth quarter of 2003. The 17 percent decline in the fourth quarter of 2004 compared to the third quarter to 2003 was mainly due to a 16 percent decline in production from 5,372 boepd in Q3 2004 to 4,527 boepd in Q4 2004. Production in Q4 2003 was 5,775 boepd compared to 4,527 for Q4 2004. This difference was mainly due to production declines at the Trust's Shane property.

Stock-Based Compensation

Stock-based compensation was \$2.0 million in Q4 2004 compared to \$0.3 million in Q3 2004 due to the plan of arrangement, which triggered the exercise of the options which were outstanding and the recognition of the entire expense for the options.

Refer to the 2004 compared to 2003 MD&A for explanations for other variances.

Application of Critical Accounting Estimates

The significant accounting policies used by TKE are disclosed in note 1 to the Consolidated Financial Statements. Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. The following discusses such accounting policies and is included in Management's Discussion and Analysis to aid the reader in assessing the critical accounting policies and practices of the Trust and the likelihood of materially different results being reported. TKE's management reviews its estimates regularly. The emergence of new information and changed circumstances may result in actual results or changes to estimated amounts that differ materially from current estimates.

The following assessment of significant accounting policies is not meant to be exhaustive. The Trust might realize different results from the application of new accounting standards promulgated, from time to time, by various rule-making bodies.

Proved Oil and Gas Reserves

Under NI 51-101, "Proved" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable (it is likely that the actual remaining quantities recovered will exceed the estimated Proved reserves). In accordance with this definition, the level of certainty targeted by the reporting company should result in at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated reserves. There was no such consideration of probability under the Canadian Securities Administrators' National Policy 2-B ("NP-2B"). In the case of "Probable" reserves, which are obviously less certain to be recovered than Proved reserves, NI 51-101 states that it must be equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated Proved plus Probable reserves. With respect to the consideration of certainty, in order to report reserves as Proved plus Probable, the reporting company must believe that there is at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated Proved plus Probable reserves. The implementation of NI 51-101 has resulted in a more rigorous and uniform standardization of Reserve evaluation.

The oil and gas reserve estimates are made using all available geological and reservoir data as well as historical production data. Estimates are reviewed and revised as appropriate. Revisions occur as a result of changes in prices, costs, fiscal regimes, reservoir performance or a change in the Trust's plans. The effect of changes in proved oil and gas reserves on the financial results and position of the Trust is described under the heading "Full Cost Accounting for Oil and Gas Activities".

Full Cost Accounting for Oil and Gas Activities

Depletion Expense

The Trust uses the full cost method of accounting for exploration and development activities. In accordance with this method of accounting, all costs associated with exploration and development are capitalized whether successful or not. The aggregate of net capitalized costs and estimated future development costs less estimated salvage values is amortized using the unit-of-production method based on estimated proved oil and gas reserves.

An increase in estimated proved oil and gas reserves would result in a corresponding reduction in depletion expense. A decrease in estimated future development costs would result in a corresponding reduction in depletion expense.

Withheld Costs

Certain costs related to unproved properties may be excluded from costs subject to depletion until proved reserves have been determined or their value is impaired. These properties are reviewed quarterly and any impairment is transferred to the costs being depleted or, if the properties are located in a cost centre where there is no reserve base, the impairment is charged directly to earnings.

Full Cost Accounting Ceiling Test

The carrying value of property, plant and equipment is reviewed at least annually for impairment. Impairment occurs when the carrying value of the assets is not recoverable by the future undiscounted cash flows. The cost recovery ceiling test is based on estimates of proved reserves, production rate, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material. Any impairment would be charged as additional depletion and depreciation expense.

Impairment of Long-Lived Assets

The Trust is required to review the carrying value of all property, plant and equipment, including the carrying value of oil and gas assets, for potential impairment. Impairment is indicated if the carrying value of the long-lived asset or oil and gas cost centre is not recoverable by the future undiscounted cash flows. If impairment is indicated, the amount by which the carrying value exceeds the estimated fair value of the long-lived asset is charged to earnings.

Fair Value of Derivative Instruments

Periodically TKE utilizes financial derivatives to manage market risk. The purpose of the hedge is to provide an element of stability to TKE's cash flow in a volatile environment. TKE discloses the estimated fair value of open hedging contracts as at the end of a reporting period. Effective January 1, 2004 TKE adopted CICA Accounting Guideline 13, "Hedging Relationships" ("AcG-13").

The estimation of the fair value of certain hedging derivatives requires considerable judgment. The estimation of the fair value of commodity price hedges requires sophisticated financial models that incorporate forward price and volatility data and, which when compared with TUSK's open hedging contracts, produce cash inflow or outflow variances over the contract period. The estimate of fair value for interest rate and foreign currency hedges is determined primarily through quotes from financial institutions. Accounting rules for transactions involving derivative instruments are complex and subject to a range of interpretation.

Asset Retirement Obligations

Effective January 1, 2004, the Trust changed its accounting policy with respect to accounting for asset retirement obligations. The Trust, under the current policy, is required to provide for future removal and site restoration costs. The Trust must

estimate these costs in accordance with existing laws, contracts or other policies. These estimated costs are charged to earnings and the appropriate liability account over the expected service life of the asset. When the future removal and site restoration costs cannot be reasonably determined, a contingent liability may exist. Contingent liabilities are charged to earnings when management is able to determine the amount and the likelihood of the future obligation.

Income Tax Accounting

The determination of the Trust's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded by management.

Business Combinations

Over recent years TKE has grown considerably through combining with other businesses. TKE acquired Del Roca Energy Ltd. and Sunfire Energy Corporation in 2003. These transactions were accounted for using what is now the only accounting method available, the purchase method. Under the purchase method, the acquiring company includes the fair value of the assets of the acquired entity on its balance sheet. The determination of fair value necessarily involves many assumptions. The valuation of oil and gas properties primarily relies on placing a value on the oil and gas reserves. The valuation of oil and gas reserves entails the process described above under the caption "Proved Oil and Gas Reserves" but in contrast incorporates the use of economic forecasts that estimate future changes in prices and costs. In addition this methodology is used to value unproved oil and gas reserves. The valuation of these reserves, by their nature, is less certain than the valuation of proved reserves.

Goodwill

The process of accounting for the purchase of a trust, described above, results in recognizing the fair value of the acquired trust's assets on the balance sheet of the acquiring company. Any excess of the purchase price over fair value is recorded as goodwill. Since goodwill results from the culmination of a process that is inherently imprecise the determination of goodwill is also imprecise. In accordance with the recent issuance of CICA section 3062, "Goodwill and Other Intangible Assets", goodwill is no longer amortized but assessed periodically for impairment. The process of assessing goodwill for impairment necessarily requires TKE to determine the fair value of its assets and liabilities. Such a process involves considerable judgment.

Legal, Environmental Remediation and Other Contingent Matters

The Trust is required to both determine whether a loss is probable based on judgment and interpretation of laws and regulations and determine that the loss can reasonably be estimated. When the loss is determined it is charged to earnings. The Trust's management must continually monitor known and potential contingent matters and make appropriate provisions by charges to earnings when warranted by circumstance.

New Accounting Standards

Stock-Based Compensation Plans

In September 2003, the CICA issued an amendment to Section 3870 "Stock-based Compensation and Other Stock-based Payments". This standard provides for the retroactive adoption of fair value accounting effective January 1, 2004. After January 1, 2004 the fair value of stock-based compensation and other transactions has been recognized as an expense in the financial statements.

Oil and Gas Full Cost Accounting

In July 2003, the Accounting Standards Board issued Accounting Guideline 16, "Oil and Gas Accounting – Full Cost" which replaced Guideline 5.

The new standards prescribe the recognition of impairment only if the carrying amount of a long-lived asset is not recoverable from its undiscounted cash flows and measure the impairment amount as the difference between the carrying amount and the fair value.

Continuous Disclosure Obligations

Effective March 31, 2004, the Trust and all reporting issuers in Canada are subject to new disclosure requirements as per National Instrument 51-102 "Continuous Disclosure Obligations". This new instrument is effective for fiscal years beginning on or after January 1, 2004. The instrument imposes shorter reporting periods for filing and enhanced disclosure requirement for annual and interim financial statements, MD&A and the Annual Information Form ("AIF"). Under this new instrument, it will no longer be mandatory for the trust to mail annual and interim financial statements and MD&A to shareholders, but rather these documents will be provided on an "as requested" basis. It is TKE's intention to make these documents available on the Company's website on a continuous basis.

Additional Information

Additional information regarding the Trust and its business and operations, including the annual information form ("AIF") is available on the Trust's company profiles at www.sedar.com. Copies of the AIF can also be obtained by contacting the Trust at TKE Energy Trust 1950, 700 – 4th Avenue S.W., Calgary, Alberta T2P 3J4 or by e-mail at mwiltshire@tketrust.com. This information is also accessible on the Trust's website at www.tketrust.com.

Forward Looking Statements

Certain information regarding TKE set forth in the document, including management's assessment of TKE's future plans and operations, contain forward looking statements that involve substantial known and unknown risks and uncertainties. These forward looking statements are subject to numerous risks and uncertainties, certain of which are beyond TKE's control, including the impact of general imprecision of reserve estimates, environmental risks, taxation policies, competition from other producers, the lack of availability of qualified personnel or management, stock market volatility and the ability to access sufficient capital from internal or external sources. TKE's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward looking statements and, accordingly, no assurance can be given that any of events anticipated by the forward looking statements will transpire or occur, or if any of them do so, what benefits that TKE will derive therefrom.



FINANCIAL INFORMATION

MANAGEMENT REPORT

The management of TKE Energy Trust is responsible for the financial information and operating data presented in this annual report.

The financial statements have been prepared by management in accordance with generally accepted accounting principles. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Financial statements are not precise as they include certain amounts based on estimates and judgments. Management has determined such amounts on a reasonable basis in order to ensure that the financial statements are presented fairly, in all material respects. Financial information presented elsewhere in this annual report has been prepared on a basis consistent with that in the financial statements.

TKE Energy Trust maintains systems of internal accounting and administrative controls. These systems are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that the Trust's assets are properly accounted for and adequately safeguarded.

The Audit Committee of the Board of Directors, composed of non-management directors, meets regularly with management, as well as the external auditors, to discuss auditing (external and joint venture), internal controls, accounting policy, financial reporting matters and reserves determination process. The Committee reviews the annual consolidated financial statements with both management and the independent auditors and reports its findings to the Board of Directors before such statements are approved by the Board.

The consolidated financial statements have been audited by KPMG LLP, the independent auditors, in accordance with Canadian generally accepted auditing standards on behalf of the shareholders. KPMG LLP have full and free access to the Audit Committee.

"signed"

Norman W. Holton
Chairman Chief Financial Officer
March 22, 2005

"signed"

Gordon K. Case
Vice President and and Chief Executive Officer

AUDITORS' REPORT

To the Unitholders of TKE Energy Trust

We have audited the consolidated balance sheets of TKE Energy Trust as at December 31, 2004 and 2003 and the consolidated statements of earnings and accumulated earnings and cash flows for the years then ended. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust at December 31, 2004 and 2003 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

"signed"

KPMG, LLP
Chartered Accountants
Calgary, Canada
March 22, 2005

Consolidated Balance Sheets

	December 31 2004	December 31 2003 (Restated – Note 4)
ASSETS	(\$)	(\$)
Current Assets		
Cash	33,226	84,249
Accounts Receivable	11,147,688	11,643,716
Prepaid Expenses	1,994,287	857,483
	13,175,201	12,585,448
Investment	–	826,246
Property, Plant and Equipment (Note 7)	142,698,993	146,551,551
Goodwill	11,160,724	11,160,724
	167,034,918	171,123,969
LIABILITIES AND UNITHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable	21,392,456	15,844,774
Bank Indebtedness (Note 8)	33,670,000	45,300,000
Cash Distribution Payable	1,880,307	–
Current Portion of Obligations Under Capital Lease (Note 9)	210,487	925,420
	57,153,250	62,070,194
Obligations Under Capital Lease (Note 9)	310,212	522,131
Asset Retirement Obligations (Note 4)	4,272,103	3,446,000
Future Income Taxes (Note 11)	38,674,980	36,174,980
Unitholders' Equity		
Unitholders Capital (Note 10)	58,835,853	53,985,151
Exchangeable Shares of Subsidiary (Note 10)	6,179,712	–
Contributed Surplus (Note 10)	233,204	–
Accumulated Earnings	3,293,291	14,925,513
Accumulated Cash Distributions	(1,917,687)	–
	66,624,373	68,910,664
Commitments and Contingencies (Note 12)	167,034,918	171,123,969

See Accompanying Notes

Approved on Behalf of the Board:

“signed”

Norman W. Holton
Director

“signed”

Jeffrey W. C. Arsenych
Director

Consolidated Statements of Earnings and Accumulated Earnings

	For the Year Ended December 31 2004	For the Year Ended December 31 2003 (Restated – Note 4)
	(\$)	(\$)
Revenue		
Oil and Gas Revenues	76,631,065	61,906,862
Royalties, Net of Alberta Royalty Tax Credit	18,618,312	12,372,279
	58,012,753	49,534,583
Expenses		
Oil and Gas Operating	13,872,852	8,935,754
Interest on Debt	2,036,002	1,961,471
General and Administrative	2,409,180	2,201,672
Stock-Based Compensation	2,709,753	–
Depreciation and Depletion	29,806,563	24,773,000
Accretion	431,724	227,000
	51,266,074	38,098,897
Net Income Before Income Taxes	6,746,679	11,435,686
Income Taxes		
Capital	223,156	176,710
Future (Note 11)	1,020,000	1,100,000
	1,243,156	1,276,710
Net Income for the Period	5,503,523	10,158,976
Accumulated Earnings, Beginning of Period as Previously Reported	14,506,038	5,703,062
Stock-Based Compensation – Retroactive Adoption (Note 2)	(616,000)	–
Asset Retirement Obligations – Retroactive Adoption (Note 4)	419,475	369,475
Accumulated Earnings, Beginning of Period As Restated	14,309,513	6,072,537
Plan of Arrangement (Note 3)	(16,481,245)	–
Adjustment for Share Redemption	(38,500)	(1,306,000)
Accumulated Earnings, End of Period	3,293,291	14,925,513
Net Income per Unit (Note 10h)		
Basic	0.33	0.77
Diluted	0.33	0.75

See Accompanying Notes

Consolidated Statements of Cash Flows

	For the Year Ended December 31 2004	For the Year Ended December 31 2003
		(Restated -- Note 4)
	(\$)	(\$)
Operating Activities		
Operating Activities		
Net Income	5,503,523	10,158,976
Items not Requiring Cash:		
Stock Based Compensation	2,709,753	—
Depreciation, Depletion and Accretion	30,238,287	25,000,000
Future Income Taxes	1,020,000	1,100,000
Asset Retirement Expenditures	—	(18,189)
Funds from Operations	39,471,563	36,240,787
Change in Non-cash Working Capital	1,896,260	(3,702,918)
Cash Provided by Operating Activities	41,367,823	32,537,869
Financing Activities		
Issue of Units	8,032,800	39,948,366
Plan of Arrangement	(4,238,350)	—
Share Issue Costs	(103,655)	(2,425,996)
Repurchase of Units	(107,160)	(2,388,934)
Bank Indebtedness	(9,630,000)	12,676,265
Obligations Under Capital Lease	(926,852)	(65,672)
Loans to Officers and Directors	—	475,306
Changes in Non-Cash Working Capital	(519,697)	—
	(7,492,914)	48,219,335
Investing Activities		
Investments	31,907	—
Property, Plant and Equipment	(37,652,325)	(34,843,843)
Acquisitions of Subsidiary, Net of Cash Acquired	—	(52,078,867)
Change in Non-Cash Working Capital	3,694,486	6,232,599
	(33,925,932)	(80,690,111)
Increase (Decrease) in Cash and Cash Equivalents During the Year	(51,023)	67,093
Cash and Cash Equivalents: Beginning of Year	84,249	17,156
Cash and Cash Equivalents: End of Year	33,226	84,249
Taxes Paid	109,509	26,710
Interest Paid	2,057,108	1,811,829
See Accompanying Notes		

Notes to Consolidated Financial Statements

TKE Energy Trust ("TKE" or the "Trust") is an open-ended, unincorporated investment trust governed by the laws of the province of Alberta. The Trust was established as part of a Plan of Arrangement (the "Arrangement") that became effective on November 2, 2004.

The reorganization resulted in the shareholders of TUSK Energy Inc. receiving trust units or exchangeable shares in the Trust, a new energy trust that owns approximately 95 percent of the assets formerly held by TUSK Energy Inc. In addition, the shareholders of TUSK Energy Inc. received shares in a separate, publicly-listed, exploration-focused company TUSK Energy Corporation ("TUSKEx"). The remaining 5 percent of the assets of TUSK Energy Inc. were transferred to TUSKEx.

Pursuant to the Arrangement, shareholders of TUSK Energy Inc. received shares of TUSKEx and at their election, either units of the Trust, which pays monthly cash distributions or exchangeable shares of a subsidiary of the Trust which may be exchanged into units of the Trust. The Arrangement resulted in TUSK Energy Inc. shareholders receiving one trust unit or exchangeable share of the Trust and one of a share in TUSKEx for every two shares of TUSK Energy Inc.

As part of the Arrangement, the Trust put in place new credit facilities totalling \$47.5 million to replace existing debt (refer to note 8, Bank Indebtedness).

Upon completion of the Arrangement, 15.9 million trust units and 1.8 million exchangeable shares were outstanding.

The conversion of TUSK Energy Inc. to a Trust has been accounted for as a continuity of interest. Accordingly, the consolidated financial statements for 2004 reflect the financial position, results of operations and cash flows as if the Trust had always carried on the business formerly carried on by TUSK Energy Inc. The year ended December 31, 2004 reflects the results of operations and cash flows of TUSK Energy Inc. and its subsidiaries for the period January 1 to November 1, 2004 and the results of operations and cash flows of the Trust and its subsidiaries for the period November 2 to December 31, 2004. The comparative figures are the results of TUSK Energy Inc. and its subsidiaries. Due to the conversion into an energy trust, certain information included in the financial statements for prior periods may not be directly comparable.

The term "units" has been used to identify both the Trust units and exchangeable shares of the Trust issued on or after November 2, 2004 as well as the common shares of TUSK Energy Inc. outstanding prior to the conversion on November 2, 2004.

Relationship with TUSK Energy Corporation

In conjunction with the Plan of Arrangement, TUSKEx and TKE entered into a Technical Services Agreement which provides for the shared services required to manage TUSKEx's activities and govern the allocation of general and administrative expenses between the entities. Under the Technical Services Agreement, TUSKEx is charged a technical services fee by TKE, on a cost recovery basis, in respect of management, development, exploitation, operations and marketing activities on the basis of relative production and capital expenditures. For the period ended December 31, 2004 (the "period") the technical services fee was \$245,000. The Technical Services Agreement has no set termination date and will continue until terminated by either party with six months prior written notice to the other party or at some other date as may be mutually agreed.

As a result of the Plan or Arrangement, TUSKEx and TKE have joint interest in certain properties and undeveloped land. These joint interest properties are governed by standard industry agreements.

As at December 31, 2004, accounts receivable and accounts payable included \$1.79 million due to TUSKEx, which includes standard joint venture amounts, including revenue. During the period, TUSKEx reimbursed TKE approximately \$1.3 million for capital expenditures, incurred between the announcement of the Plan of Arrangement and the information of TUSKEx, that are related to lands subsequently owned by TUSKEx.

1. Accounting Policies

a) Nature of Business and Basis of Presentation

TKE is involved in the production, development and exploration of petroleum and natural gas in British Columbia, Alberta and Saskatchewan. The financial statements are stated in Canadian dollars and have been prepared in accordance with Canadian generally accepted accounting principles.

The preparation of financial statements in conformity with generally accepted accounting principles required management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets

and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from those estimates.

b) Joint Operations

Substantially all of the exploration, development and production activities are conducted jointly with others and accordingly, the Trust only reflects its proportionate interest in such activities.

c) Measurement Uncertainty

The amounts recorded for depletion and depreciation of petroleum and natural gas property, plant and equipment and the provision for asset retirement obligations are based on estimates. The cost recovery ceiling test is based on estimates of proved reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be significant.

d) Cash and Cash Equivalents

Cash and cash equivalents consists of cash in the bank, less outstanding cheques and short-term deposits with an original maturity of less than three months.

e) Petroleum and Natural Gas Properties

The Trust follows the full cost method of accounting for petroleum and natural gas operations, whereby all costs related to the acquisition, exploration and development of petroleum and natural gas reserves are capitalized. Such costs include lease acquisition costs, geological and geophysical costs, carrying charges of non-producing properties, costs of drilling both productive and non-productive wells, the cost of petroleum and natural gas production equipment and overhead charges related to exploration and development activities.

Petroleum and natural gas assets are evaluated at least annually to determine that the costs are recoverable and do not exceed the fair value of the properties. The costs are assessed to be recoverable if the sum of the undiscounted cash flows expected from the production of proved reserves and the lower of cost and market of unproved properties exceed the carrying value of the petroleum and natural gas assets. If the carrying value of the petroleum and natural gas assets is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying value exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves and the lower of cost and market of unproved properties. The cash flows are estimated using the future product prices and costs are discounted using the risk-free rate. Proceeds from the disposition of petroleum and natural gas properties are applied against capitalized costs except for dispositions that would change the rate of depletion and depreciation by 20% or more, in which case a gain or loss would be recorded.

f) Depletion and Depreciation

Capitalized costs, together with estimated future capital costs associated with proved reserves, are depleted and depreciated using the unit-of-production method based on estimated gross proved reserves of petroleum and natural gas as determined by independent engineers. For purposes of this calculation, reserves and production are converted to equivalent units of oil based on relative energy content of six thousand cubic feet of gas to one barrel of oil. Costs of significant unproved properties, net of impairments, are excluded from the depletion and depreciation calculation.

g) Goodwill

Goodwill is tested for impairment on an annual basis in the fourth quarter. If indications of impairment are present, a loss would be charged to earnings for the amount that the carrying amount of the goodwill exceeds its fair value.

h) Asset Retirement Obligations

The Trust records a liability for the fair value of legal obligations associated with the retirement of long-lived tangible assets in the period in which they are incurred, normally when the asset is purchased or developed. On recognition of the liability there is a corresponding increase in the carrying amount of the related asset known as the asset retirement cost, which is depleted on a unit-of-production basis over the life of the proved reserves. The liability is adjusted each reporting period to reflect the passage of time, with the accretion charged to earnings, and for revisions to the estimated future cash flows. Actual costs incurred upon settlement of the obligations are charged against the liability.

i) Revenue Recognition

Revenues from the sale of petroleum and natural gas are recorded when title passes to an external party.

j) Transportation Expenses

Transportation expenses are presented as an expense in the Statement of Operations and Accumulated Earnings.

k) Financial Instrument

The Trust periodically used certain financial instruments to hedge its exposure to commodity price and foreign exchange fluctuations on a portion of its crude oil and natural gas sales. Gain and losses on these transactions are reported as adjustments to revenue when the hedged production is sold.

l) Income Taxes

The Trust is a taxable entity under the Income Tax Act (Canada) and is taxable only on income that is not distributed or distributable to the unit holders. The Trust subsidiaries follow the liability method of accounting for income taxes. Temporary differences arising from the differences between the tax basis of an asset or liability and its carrying amount on the balance sheet are used to calculate future income tax assets or liabilities. Future income tax assets or liabilities are calculated using tax rates anticipated to apply in the periods that the temporary differences are expected to reverse.

m) Unit Based Compensation Plan

The Trust applies the fair value method for valuing trust unit incentive rights. Under this method, compensation cost, attributable to trust unit incentive rights granted to officers,¹ directors and other service providers of TKE is measured at fair value at the grant date and expensed with a corresponding increase to contributed surplus. Upon the exercise of the trust unit incentive rights, consideration paid together with the amount previously recognized in contributed surplus is recorded as an increase to share capital.

The Trust has not incorporated an estimated forfeiture rate for incentive rights, rather, the trust accounts for actual forfeiture as they occur.

n) Per Unit Information

Per unit information is calculated on the basis of the weighted average number of Trust Units outstanding during the fiscal year. Diluted per unit information reflects the potential dilution that could occur if securities or other contracts to issue Trust Units were exercised or converted to Trust Units. Diluted per share information is calculated using the treasury stock method that assumes any proceeds received by the Units upon the exercise of in-the-money stock options plus the unamortized stock compensation cost would be used to buy back Trust Units at the average market price for the period.

2. Change in Accounting Policies**a) Asset Retirement Obligations**

Effective January 1, 2004 the Trust retroactively adopted the new Canadian accounting standard for asset retirement obligations. The new recommendations require that the recognition of the fair value of obligations associated with the retirement of tangible long-lived assets be recorded in the period the asset is put into use, with a corresponding increase to the carrying amount of the related asset. The obligations recognized are statutory, contractual or legal obligations. The liability is accreted over time for changes in fair value of the liability through charges to accretion expense. The costs capitalized to the related assets are amortized to earnings in a manner consistent with the depreciation, depletion and amortization of the underlying asset. Note 4 discloses the impact of the adoption of the new standard on the financial statements.

b) Stock-based Compensation

Effective January 1, 2004 the Trust adopted the new Canadian accounting standard for stock based compensation, retroactively without restatement of prior periods. The recommendations require the Trust to record a compensation expense with a corresponding increase to contributed surplus over the vesting period based in the fair value of options granted to employees and directors. Upon the exercise of options, consideration received together with the amount previously recognized in contributed surplus is recorded as an increase to share capital. This change resulted in a decrease to accumulated earnings of \$616,000, an increase to contributed surplus of \$600,000 and an increase to share capital of \$16,000.

c) Property, Plant and Equipment – Oil and Gas

Effective January 1, 2004 the Trust adopted new Canadian guidelines which modify the way the ceiling test is performed. The recoverability of a cost centre is tested by comparing the carrying value of the cost centre to the sum of the undiscounted cash flows expected from the cost centre's use and eventual disposition. If the carrying value is unrecoverable the cost centre is written down to its fair value using the expected future cash flows which are discounted using a risk free rate. The adoption of the new guidelines had no effect on the Trust's financial results.

d) Hedging Relationships

Effective January 1, 2004, the Trust adopted the new Canadian accounting guideline relating to hedging relationships which requires the identification, designation and documentation of each hedging relationship as well as an assessment of the effectiveness of the hedging relationship. The guideline does not specify how hedge accounting is applied, and accordingly, the Trust's derivative financial instrument accounting policy in the 2003 annual consolidated financial statements remains unchanged. Adoption of the new guideline had no effect on the Trust's financial statements.

3. Plan of Arrangement

Under the Arrangement, TUSK Energy Inc. transferred to TUSKEx certain assets and liabilities. The details are as follows:

	Amount (\$)
Investment	794,339
Petroleum and Natural Gas Properties	13,452,953
Future Income Tax Asset	2,060,000
Accounts Payable Assumed	(1,524,397)
Bank Debt Assumed	(2,000,000)
Net Assets Transferred and Reduction on Accumulated Earnings	12,782,895
Plan of Arrangement Costs, Net of Income Tax Benefit of \$540,000	3,698,350
Total Plan of Arrangement and Reduction in Accumulated Earnings	16,481,245

4. Asset Retirement Obligations

The Trust retroactively adopted the new recommendations on the recognition of the obligations to retire long-lived tangible assets. The change was effective January 1, 2004 and the revision was applied retroactively.

The effect of the adoption is presented below as increases (decreases):

Balance Sheet	As of December 31, 2003
Asset Retirement Costs, Included in Property, Plant and Equipment	3,068,000
Accumulated Amortization on Asset Retirement Costs Included in Property, Plant and Equipment	464,000
Asset Retirement Obligations	3,446,000
Site Restoration Liability	(1,536,475)
Future Income Tax Liability	275,000
Retained Earnings	419,475
Income statement	Year Ended December 31, 2003
Accretion Expense	227,000
Depletion and Depreciation on Asset Retirement Costs	336,000
Provision for Future Site Restoration	(613,000)
Net Income Impact	50,000
Net Income per Share – Basic	–
– Diluted	–

The Trust's asset retirement obligations result from net ownership interests in petroleum and natural gas assets including well sites, gathering systems and processing facilities. The Trust estimates the total undiscounted amount of cash flows required to settle its asset retirement obligations is approximately \$16.9 million which will be incurred between 2005 and 2050. The majority of the costs will be incurred between 2010 and 2020. A credit-adjusted risk-free rate of 9.1% percent and an inflation rate of 2.0 percent were used to calculate the fair value of the asset retirement obligation.

A reconciliation of the asset retirement obligations is provided below:

	Year ended December 31, 2004	Year end December 31, 2003
Asset retirement obligations		
Balance, Beginning of Period	3,446,000	764,000
Liabilities Incurred in Period	394,379	2,455,000
Liabilities Settled in Period	—	—
Accretion Expense	431,724	227,000
Balance, End of Period	4,272,103	3,446,000

5. Acquisition of Del Roca Energy Ltd.

On January 29, 2003 the Trust acquired all of the issued and outstanding shares of Del Roca Energy Ltd., a public company engaged in the exploration for and production of natural gas and crude oil in Western Canada. The transaction was accounted for using the purchase method with the results of operations being included from the date of acquisition.

	\$
Consideration given	
Cash	6,335,443
Transaction Costs	227,142
Total Cash Consideration	6,562,585
Non-Cash Issue of 2,800,000 Common Shares @ \$2.56 per share	7,117,819
	13,680,404

Allocation of Purchase Price

Capital Assets	23,369,825
Future Income Taxes	(4,904,161)
Future Site Restoration	(247,541)
Working Capital	686,016
Bank Indebtedness	(5,223,735)
	13,680,404

6. Acquisition of Sunfire Energy Corporation

On June 30, 2003 the Trust acquired all of the issued and outstanding shares of Sunfire Energy Corporation a public company engaged in the exploration for and production of natural gas and crude oil in Western Canada. The transaction was accounted for using the purchase method with the results of operations being included from the date of acquisition.

	\$
Consideration given	
Cash	44,910,631
Transaction Costs	843,656
Total Cash Consideration	45,754,287

Allocation of Purchase Price

Capital Assets	66,270,656
Goodwill	11,160,724
Future Income Taxes	(15,997,944)
Future Site Restoration	(275,662)
Working Capital (includes cash of \$238,005)	262,839
Obligations Under Capital Lease	(466,326)
Bank Indebtedness	(15,200,000)
	45,754,287

7. Property, Plant and Equipment

	December 31, 2004		
	Cost	Accumulated Depletion and Depreciation	Net Book Value
	(\$)	(\$)	(\$)
Oil and Gas Properties	218,862,996	76,723,633	142,139,363
Furniture and Equipment	1,092,416	532,786	559,630
	219,955,412	77,256,419	142,698,993

	December 31, 2003		
	Cost	Accumulated Depletion and Depreciation	Net Book Value
	(\$)	(\$)	(\$)
Oil and Gas Properties	193,027,150	47,083,932	145,943,218
Furniture and Equipment	974,256	365,923	608,333
	194,001,406	47,449,855	146,551,551

The calculation of 2004 depletion and depreciation included an estimated \$10.2 million for future development costs associated with proved undeveloped reserves and excluded \$2.1 million for the estimated future net realizable value of production equipment and facilities and \$28.9 million for the estimated value of unproven properties.

Included in the Trust's property, plant and equipment balance is \$2.6 million, net of accumulated depletion, related to asset retirement obligations (\$3.1 million before accumulated depletion) (Refer to note 4).

The Trust capitalized approximately \$1.8 million of geological and geophysical expenses associated with the exploration and development of capital assets during the year ended December 31, 2004 (2003 – \$1.4 million).

Adoption of the new guideline for oil and gas accounting using the full cost method, as outlined in note 1, had no effect on the Trust's financial statements, based on the ceiling test prepared on initial adoption on January 1, 2004 using commodity price forecasts of the Trust's independent reserve engineers adjusted for differentials specific to the Trust's reserves. The Trust performed a ceiling test calculation at December 31, 2004 resulting in the undiscounted cash flows from proved reserves and the lower of cost and market of unproved properties exceeding the carrying value of oil and gas assets. The following table summarizes the future benchmark prices the Trust used in the ceiling test:

	Crude Oil		Natural Gas
	West Texas (US\$/bbl)	Edmonton (Cdn\$/bbl)	AECO (Cdn\$/mmbtu)
2005	42.00	50.22	6.55
2006	40.00	49.00	6.30
2007	38.00	47.72	5.80
2008	36.00	45.15	5.55
2009	35.00	43.87	5.63
Thereafter ⁽²⁾	1.5%	1.5%	1.5%

(1) Future prices incorporated a \$0.82 US/Cdn exchange rate for 2005, \$0.80 US/Cdn for 2006 and \$0.78 US/Cdn thereafter.

(2) Percentage change of 1.5% represents the change in future prices each year after 2009 to the end of the reserve life.

8. Bank Indebtedness

Bank indebtedness is a revolving loan in the amount of \$47,500,000 and bears interest at the bank's prime lending rate plus 0.375% for the fourth quarter and is adjusted based on debt cash flow ratio, as defined, each quarter. The loan is scheduled to be reviewed no later than June 30, 2005. At December 31, 2004 the bank's prime lending rate was 4.25%. The loan is secured by a

\$100,000,000 floating charge debenture over the majority of the assets of the Trust and a general security agreement covering all present property of the Trust. The Trust is required to meet certain financial and engineering reporting requirements.

9. Obligations Under Capital Lease

Leases relating to gas compression and other equipment, having initial costs totalling \$1.2 (2003 – \$1.7 million) million have been classified as capital leases and are included in capital assets. The capital lease obligations have implicit interest rates of 5.78% to 8.50% and are repayable as follows: 2005 – \$210,487, 2006 – \$254,346 and 2007 – \$57,298.

10. Unitholders' Capital

The Trust Indenture provides that an unlimited number of trust units may be authorized and issued. Each trust unit is transferable, carries the right to one vote and represents an equal undivided beneficial interest in any distributions from the Trust and in the net assets of the Trust in the event of termination or winding-up of the Trust. All trust units are of the same class with equal rights and privileges. Trust units are redeemable at any time at 90% of the market price as defined to a maximum of \$250,000 per calendar month.

a) Trust Units of TKE Energy Trust

	2004		2003	
	Number	Amount	Number	Amount
Trust Units				
Balance Beginning of Year	—	—	—	—
Issued for Common Shares	15,860,371	58,355,673	—	—
Issued for Cash	4,202	37,380	—	—
Exchangeable Shares Converted	120,353	442,800	—	—
Balance, End of Year	15,984,926	58,835,853	—	—

b) Exchangeable Shares of Subsidiary

	2004		2003	
	Number	Amount	Number	Amount
Balance Beginning of Year	—	—	—	—
Issued in Exchange for Common Shares	1,800,000	6,622,512	—	—
Exchanged for Trust Units	(120,353)	(442,800)	—	—
Balance, End of Year	1,679,647	6,179,712	—	—

The exchangeable shares are non-voting and can be converted, at the option of the holder into trust units at any time. If the number of exchangeable shares outstanding is less than 180,000, the Trust can elect to redeem the exchangeable shares for trust units or an amount in cash equal to the amount determined by multiplying the exchange ratio on the last business day prior to the redemption date by the current market price of a trust unit on the last business day prior to such redemption date. The number of trust units issued upon conversion is based on the exchange ratio in effect on the date of conversion. The exchange ratio is calculated monthly based on the five day weighted average trust unit trading price preceding the monthly effective date. The exchangeable shares are not eligible for cash distributions, however cash distributions will increase the exchange ratio.

Retraction of Exchangeable Shares

Exchangeable shares may be redeemed their shares at any time by delivering the share certificates to the Trustee, together with a properly completed retraction request. The retraction price will be satisfied with trust units equal to the amount determined by multiplying the exchange ratio on the last business day prior to the retraction date by the number of exchangeable shares redeemed.

Redemption of Exchangeable Shares

On January 15, 2010 the exchangeable shares will be redeemed by the Trust unless the Board of Directors of TKE Energy Inc. elect to extend the redemption period. The exchangeable shares will be redeemed by either issuing units for an amount equivalent to the value of the exchangeable shares at the current exchange ratio.

c) **Common Shares of TUSK Energy Inc.**

	December 31, 2004		December 31, 2003	
	Number	Amount	Number	Amount
Balance Beginning of Year	32,427,705	53,985,151	17,613,774	13,002,896
Adjustment	(16,363)	—	—	—
Issued for Cash				
Exercise of Stock Options	2,935,000	8,032,800	1,110,333	960,866
Issuance of Common Shares	—	—	12,280,398	36,092,819
Issuance of Flow-Through Common Shares	—	—	2,225,000	10,012,500
Less: Tax Effect of Flow Through Shares	—	—	—	(3,400,000)
Stock Based Compensation				
Expense of Options Exercised	—	3,076,549	—	—
Repurchased under Normal Course Issuer Bid	(25,600)	(68,660)	(801,800)	(1,082,933)
Stock-based Compensation Adjustment	—	16,000	—	—
Less: Share Issue Expenses,				
Net of Tax Effect of \$40,000 in 2004 & \$825,000 in 2003	—	(63,655)	—	(1,600,997)
Exchanged for Trust Units	31,720,742	(58,355,673)	—	—
Exchanged for Exchangeable Shares	(3,600,000)	(6,622,512)	—	—
Balance, End of Year	—	—	32,427,705	53,985,151

d) **Trust Unit Incentive Plan**

The Trust has a trust unit incentive plan where the Trust may grant trust unit incentive rights to its directors, officers and service providers for up to 1,766,000 trust units. Trust unit incentive rights issued in excess of 1,766,000 are subject to shareholder approval at the next unitholders meeting. Under this plan, the exercise price of each trust unit incentive right equals the market price of the Company's stock on the date of grant. The maximum term of an incentive right is 10 years.

The grant price per Incentive Right ("Grant Price") shall be equal to the per Trust Unit closing price on the trading day immediately preceding the date of grant, unless otherwise permitted. Under the terms of the Incentive Plan, the exercise price of each Incentive Right is reduced pursuant to a formula. This formula provides that the exercise price of each Incentive Right is reduced by any decreases in the daily closing prices on the TSX of the Trust Units that is in excess of a 2.5% return on TKE Trust's consolidated net fixed assets (the "Hurdle Rate"); provided however, that such decrease in the exercise price will not exceed the amount by which the Trust Unit distributions exceed the Hurdle Rate. In no case may the exercise price be less than \$0.001 per Trust Unit and a participant may elect to have the exercise price equal the Grant Price. Incentive Rights are not transferable or assignable except in accordance with the Incentive Plan and the holding of Incentive Rights shall not entitle a holder to any rights as a Unitholder of TKE Trust.

Unit rights, entitling the holder to purchase units from the Trust, have been granted to directors, officers and service providers of the Trust. Trust unit incentive rights vest one third on each of the first, second and third anniversary from the date of grant.

The following table summarizes information regarding trust unit incentives rights at December 31, 2004 which were granted November 16, 2004:

Unit Rights Outstanding

Exercise Price (\$)	Number Outstanding	Number Exercisable	Weighted Average Remaining Contractual Life
9.51	1,766,000	—	4.9

e) Unit –based Compensation

The fair values of all incentive rights granted are estimated on the date of grant using the Black-Scholes option-pricing model. The weighted average fair market value of incentive rights granted during the year ended December 31, 2004 and the assumptions used in their determination are as noted below:

	Year Ended December 31, 2004
Weighted Average Fair Market Value per Right	3.143
Risk-free Interest Rate (percent)	3.03%
Volatility (percent)	37%
Expected Life (years)	5

As described in note 2, the Trust adopted the fair value based method of accounting for stock-based compensation for its stock option plan retroactively without restatement of prior periods. Accumulated earnings at January 1, 2004 was decreased by \$616,000 with an increase to contributed surplus of \$600,000 and an increase to common share capital of \$16,000. Beginning January 1, 2004, stock compensation is being recognized in earnings.

f) Contributed Surplus

The following table reconciles the Trust's contributed surplus:

	Year Ended December 31, 2004	Year Ended December 31, 2003
Balance, Beginning of Year	–	–
Retroactive Adoption of Unit Based Compensation	600,000	–
Unit Based Compensation Expense	2,709,753	–
Unit Rights Exercised	(3,076,549)	–
Balance, End of Year	233,204	–

g) Stock Option Plan

A summary of the status of the Company's stock option plan as of December 31, 2004 and 2003, and changes during the years ending on those dates is presented below.

	2004		2003	
	Options	Weighted Average Exercise Price (\$)	Options	Weighted Average Exercise Price (\$)
Outstanding at Beginning of Year	2,720,000	2.63	1,995,000	0.92
Granted	275,000	4.03	1,882,000	3.43
Exercised	(2,935,000)	2.74	(1,110,333)	0.87
Expired/Cancelled	(60,000)	3.98	(46,667)	3.27
Outstanding and Exercisable at End of Year	–	–	2,720,000	2.63

A total of 2,650,000 stock options of TUSK Energy Inc. were exercised as part of the Plan of Arrangement.

h) Per Unit Amounts

Per unit amounts have been calculated on the weighted average number of units outstanding. The weighted average units outstanding for the year ended December 31, 2004 was 16,484,051 (2003 – 13,201,184). In computing diluted earnings per unit, 343,000 units (2003 – 391,104) were added to the weighted average number of units outstanding for the year ended December 31, 2004 for the dilutive effect of incentive rights.

11. Income Taxes

On March 31, 2004, Bill-27 Alberta Corporate Tax Amendment Act, 2004 was tabled and received first reading in the Alberta Legislative Assembly. As a result, Bill-27 is substantively enacted and a non-recurring benefit of \$590,000 was recorded in the first nine months of 2004.

Income tax expense differs from the amount that would be computed by applying the federal and provincial statutory rate of 38.87% (2003 – 41.2%) to income before income taxes. The reasons for the differences are as follows:

	Year Ended December 31, 2004	Year Ended December 31, 2003
Income Before Taxes	6,746,679	11,435,686
Less Non-Taxable Income of the Trust	(1,813,909)	—
Taxable Earnings	4,932,770	11,435,686
Combined Federal and Provincial Tax Rate	38.87%	41.2%
Expected Income Tax Expense	1,917,368	4,711,503
Non-Deductible Crown Charges	2,833,372	2,930,300
Alberta Royalty Tax Credit	(278,841)	(290,900)
Stock based Compensation	1,053,281	—
Resource Allowance	(3,549,680)	(3,481,702)
Tax Rate Reduction	(1,099,000)	(2,200,000)
Change to Estimate of Recorded Tax Basis	—	(548,598)
Other	143,500	(20,603)
Capital Taxes	223,156	176,710
	1,243,156	1,276,710

The components of the future tax liability at December 31, 2004 and 2003 are as follows:

	Year Ended December 31, 2004	Year Ended December 31, 2003
	(\$)	(\$)
Property, Plant and Equipment	41,572,980	41,704,980
Unit Issue Costs	(1,248,000)	(1,087,000)
Asset Retirement Obligations	(1,448,000)	(532,000)
Non Capital Losses	—	(3,709,000)
Investment Tax Credits	(202,000)	(202,000)
	38,674,980	36,174,980

12. Commitments and Contingencies

- The Trust entered into an agreement to lease office space for five years beginning February 1, 2003 for approximately \$336,000 per year.
- The Trust has been named in a statement of claim, for an unspecified amount, filed by a joint venture partner against the Trust and the previous operator of the Meekwap East Flank Pool alleging that the defendants had failed to account for the joint venture partner's share of revenues from the East Flank lands. The amount of the liability, if any, can not be determined at this time.

13. Financial Instruments

a) Commodity Price Contracts

The Trust has entered into several derivative financial instruments, including crude oil and natural gas costless collar and floor price contracts. The Trust enters into these contracts for the purpose of protecting its future earnings and cash flow from operations from the volatility of crude oil and natural gas commodity prices. The costless collar and floor price contracts reduce fluctuations in petroleum and natural gas revenues by locking in a floor price and, in the case of collars, also a maximum price.

The Trust has entered into several short-term arrangements for both oil and natural gas. For the year ended December 31, 2004, the Trust realized a net loss of \$778,103 (2003 – a loss of \$1,478,506) on its oil and natural gas price risk management.

Contracts outstanding in respect to financial instruments at December 31, 2004 were as follows:

Contract	Volume	Pricing Point	Strike Price	Cost/ Premium	Term
Crude Oil:					
Put Option	1,300	WTI	\$ 40.00	\$ 2.17/bbl	Jan. 01 – Dec. 31

(1) Oil volumes are in barrels per day. Gas volumes are in gigajoules per day.

(2) Strike price and any cost or premium paid is in US dollars for oil.

(3) All dates occur in 2005.

b) Credit Risk

The Trust's accounts receivable are with customers and joint venture partners in the petroleum and natural gas business and are subject to normal credit risks. To mitigate this risk, the Trust sells substantially all of its production to three primary purchasers under normal industry sale and payment terms. The Trust may be exposed to certain losses in the event on non-performance by counterparties to commodity price contracts. The Trust mitigates this risk by entering into transactions with highly rated major financial institutions.

c) Foreign Currency Exchange Risk

The Trust is exposed to foreign currency fluctuations as crude oil prices received are referenced in U.S. dollar denominated prices.

d) Fair Value of Financial Instruments

The Trust's financial instruments recognized in the balance sheet consist of accounts receivable, accounts payable, bank indebtedness and obligations under capital leases. The fair value of these financial instruments approximate their carrying amounts due to their short terms to maturity or the indexed rate of interest on the bank indebtedness.

Transactions entered into after December 31, 2004 are not reflected in the estimated fair market values shown below. At December 31, 2004 the estimated fair value of the above financial instrument transactions were as follows:

\$ Thousands Receivable (Payable)

Crude Oil Contracts	\$ 1,313,083 U.S.
---------------------	-------------------

The above estimated fair values are based on the market value of these instruments as at year-end and represent the amounts the Company would receive or pay to terminate the contracts at year-end.

14. Subsequent Event

On March 1, 2005 the Trust closed an agreement with a syndicate of underwriters to sell 2,900,000 trust units at \$10.95 per unit to raise gross proceeds of \$31,755,000. Net proceeds from the financing will be used to accelerate the Trust's ongoing capital programs, repay outstanding borrowing and for general corporate purposes.

Seven Year Review

	Years Ended December 31						
	2004	2003 (restated)	2002	2001	2000	1999	1998
Revenue							
Oil & Gas Revenues, Net	58,012,753	49,534,583	16,957,486	8,651,117	6,805,788	5,086,350	4,103,157
Expenses							
Oil & Gas Operating	13,872,852	8,935,754	2,521,492	2,079,338	2,043,410	1,543,624	1,373,765
Interest on Long-Term Debt	2,036,002	1,961,471	757,888	642,363	487,087	277,071	271,490
Provision for Site Restoration	—	—	85,000	50,400	27,600	42,100	44,997
General & Administrative	2,409,180	2,201,672	1,398,459	901,651	687,669	672,049	474,728
Stock-Based Compensation	2,709,753	—	—	—	—	—	—
Depreciation, Depletion and Accretion	30,238,287	25,000,000	6,734,100	2,889,350	1,644,700	1,386,100	1,536,100
Loss on Foreign Exchange	—	—	—	—	—	175,000	—
	51,266,074	38,098,897	11,496,939	6,563,102	4,890,466	4,095,944	3,701,080
Income Taxes	1,243,156	1,276,710	1,905,516	795,826	1,006,730	—	—
Net Income	5,503,523	10,158,976	3,555,031	1,292,189	908,592	990,406	402,077
Cash Flow from Operations							
	39,471,563	36,240,787	12,268,131	4,924,939	3,544,892	2,418,606	1,983,174
Balance Sheet							
Working Capital (Deficiency)	(10,308,049)	(4,184,745)	(1,282,181)	(1,226,789)	(2,223,265)	(44,859)	(430,714)
Other Assets	—	826,246	826,246	1,710,757	1,162,757	480,851	145,632
Property Plant & Equipment	142,698,993	146,551,551	43,900,227	36,397,539	23,246,144	11,945,325	10,767,247
Goodwill	11,160,724	11,160,724	—	—	—	—	—
Bank Indebtedness	33,670,000	45,300,000	12,200,000	13,850,000	4,350,000	3,900,000	4,338,327
Obligations Under Capital Lease	310,212	522,131	796,997	371,115	—	—	—
Asset Retirement Obligations	4,272,103	3,446,000	418,462	333,462	283,062	252,411	210,311
Future Income Taxes	38,674,980	36,174,980	11,322,875	9,448,875	5,912,249	—	—
Unitholders Equity	66,624,373	68,910,664	18,705,958	12,878,055	11,640,325	8,093,705	6,268,746
Per Unit Data							
Net Income (Loss) per Unit	0.33	0.77	0.44	0.18	0.12	0.16	0.08
Cash Flow per Unit	2.39	2.74	1.48	0.68	0.50	0.40	0.40
Production							
Oil & NGL (bopd)	1,562	1,675	1,034	404	475	562	603
Gas (Mcf)	22,134	17,710	6,063	3,760	1,417	1,036	519
Boepd	5,251	4,627	2,045	1,031	711	735	690
Reserves (Proven & Probable – 2003)							
(Established 2002– 1998)							
Oil & NGL (Mbbls)	4,089	3,905	2,356	2,231	2,204	2,967	1,370
Gas (MMcf)	65,631	58,519	20,596	21,054	14,448	14,645	11,120
Boe	15,028	13,658	5,789	5,739	4,612	5,408	3,223

PERSONNEL

Accounting & Finance

Sue Burghardt
Accounts Payable

Gord Case
Vice President

Debbie Cooke
Senior Accountant

Shynell Dobson
Accounts Payable

Maria Johnson
Production Accountant

Karla MacDonald
Joint Venture Accountant

Evelyn Studer
Assistant Controller

Carmen Truong
Joint Venture/Treasury Accountant

Nora Ring
Controller

Engineering & Production

Ed Beaman
Vice President

Jim Boyd
Consulting Engineer

Sheldon Cardinal
Junior Field Operator

Rob Coogan
Field Superintendent

Todd Curial
Area Foreman

Patrick Keck
Consulting Engineer

Ted Lichon
Senior Engineering Technologist

Rich Maiklem
Consulting Engineering Technologist

Casey Makokis
Junior Field Operator

Walter Seyer
Consulting Engineer

Elmer Whitford
Junior Field Operator

Exploration & Land

Rob Armstrong
Geological Technician

Bruce Barrie
Senior Geophysicist

Warren Blair
Land Manager

Ian Brown
Vice President

Vanessa Cartwright
Land Clerk

Dr. Colin Chen
Senior Geologist

Marshall Elliott
Land Clerk

Carol Gaskin
Supervisor Land Administration

Nicole LaPointe
Surface Land Administrator

Jean MacLean
Landman

Shirley Pocock
Land Administration Consultant

Dave Slessor
Manager of Geology

Darol Turnquist
Exploration Advisor

Dr. Victor Verkhogliad
Geologist

Corporate

Haley Blake
Administrative Assistant

Norm Holton
President

Wayne Jessee
Vice President

Michele Wiltshire
Office Manager

CORPORATE INFORMATION

Board of Directors

Jeffrey W. C. Arsenych ⁽¹⁾⁽²⁾
Calgary, Alberta

Norman W. Holton
Calgary, Alberta

Brian W. Mainwaring ⁽²⁾
Calgary, Alberta

Michael A. McVea ⁽²⁾
Victoria, B.C.

C. Alexander Squires ⁽¹⁾
Toronto, Ontario

Murray B. Todd ⁽¹⁾
Calgary, Alberta

(1) Audit & Reserves Committee

*(2) Compensation & Corporate
Governance Committee*

Officers

Norman W. Holton, P. Geol.
Chairman &
Chief Executive Officer

Gordon K. Case, CA
Vice President &
Chief Financial Officer

Ian T. Brown, P. Geol.
Vice President, Exploration

Ed. A. Beaman, P. Eng.
Vice President,
Production & Engineering

Wayne B. Jessee, P. Eng.
Vice President,
Corporate Development

Brian W. Mainwaring
Secretary

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Canadian Western Bank
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Transfer Agent & Registrar

Computershare Trust Company of Canada
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Subsidiaries

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TKE Energy Partnership

TKE Energy Trust

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The units of TKE Energy Trust trade on Toronto Stock
Exchange under trading symbol "TKE.UN"

ABBREVIATIONS

1P	Proved Reserves pursuant to NI 51-101
2P	Proved plus Probable Reserves pursuant to NI 51-101
AIF	Annual Information Form
ARTC	Alberta Royalty Tax Credit
APO	after payout
BPO	before payout
BTAX	before income tax
bbl(s)	barrel(s)
bopd	barrels of oil per day
bpd	barrels per day
boe or Boe	barrels of oil equivalent
boepd	barrels of oil equivalent per day
CBM	coal bed methane
Chapman	Chapman Petroleum Engineering Ltd.
DCF	discounted cash flow
DD&A	depletion, depreciation & amortization
F&D	finding and development
G&A	general & administrative
Mbbls or mbbbls	thousands of barrels
mmbtu	million British Thermal Units
Mcf or mcf	thousand cubic feet
Mcfd or mcfd	thousand cubic feet per day
MD&A	Management's Discussion & Analysis
MMcf or mmcf	million cubic feet
MMcfd or mmcfd	million cubic feet per day
MRL	maximum rate limitation
NAV	net asset value
NI 51-101	National Instrument 51-101
NGL	natural gas liquids
NP	National Policy
RLI	Reserve Life Index
TKE	TKE Energy Trust
Trust	TKE Energy Trust
TUSKEx	TUSK Energy Corporation

CONVERSIONS

1 barrel of oil = 0.15891 cubic metres
 1 Mcf of gas = 28.17399 cubic metres
 1 barrel of oil equivalent (boe) = 6 Mcf gas
 1 mile = 1.6 kilometres
 1 square mile = 2.56 km²



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